PB81-234239

Environmental and Economic Comparison of Advanced Processes for Conversion of Coal and Biomass into Clean Energy

Bechtel National, Inc.
San Francisco, CA

Prepared for

Industrial Environmental Research Lab.
Cincinnati, OH

Aug 81

U.S. Department of Commerce
National Technical Information Service
NTIS

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-600/7-81-133	2. ORD Report	3. RECIPIENT'S ACCESSION NO. PB81 234239
4. TITLE AND SUBTITLE Environmental and Economic Comparison of Advanced Processes for Conversion of Coal and Biomass into Clean Energy		5. REPORT DATE August 1981
		6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) R. A. Stenzel, B. T. Kown, M. C. Weekes, J. D. Ruby, B. R. Gilbert, C. M. Harper, Y. J. Yim, R. T. Milligan		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS Bechtel National, Inc. P.O. Box 3965 San Francisco, CA 94119		10. PROGRAM ELEMENT NO. C2G1E
		11. CONTRACT/GRANT NO. 68-02-2616
12. SPONSORING AGENCY NAME AND ADDRESS Industrial Environmental Research Lab, Cinn, OH Office of Research and Development U.S. Environmental Protection Agency Cincinnati, OH 45268		13. TYPE OF REPORT AND PERIOD COVERED Final - 9/77 - 12/78
		14. SPONSORING AGENCY CODE EPA/600/12

15. SUPPLEMENTARY NOTES

Project Officer - Thomas J. Powers (513-684-4363)

16. ABSTRACT

Biomass and coal conversion into clean energy is compared on an economic and environmental basis in three regional scenarios: (1) electric power from direct combustion of wood versus conventional coal combustion in the South Central U.S., (2) synthetic pipeline gas from anaerobic digestion of wheat straw and manure versus high-Btu gasification of coal (HYGAS^R) in the Midwest, and (3) synthetic fuel oil from wood liquefaction versus coal liquefaction (H-Coal^R) in the Northeast. Conceptual commercial-scale plants are described. Capital and operating costs are presented for each of the six plants, and the biomass versus coal economics are compared. General environmental impacts of biomass and coal resource collection are assessed and compared in the scenario contexts. Plant environmental emissions were estimated where possible, and relative environmental impacts are discussed. Conclusions are given about the conversion concepts which seem the more promising routes to clean energy, and areas needing further study are identified.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Biomass*, Coal*, Energy*, Combustion, Gasification, Liquefaction, Pollution, Economic analysis	Synthetic fuels, Anaerobic digestion, Environmental assessments, Pollution control, Solid waste, Management, HYGAS, H-coal	

18. DISTRIBUTION STATEMENT Release to Public	19. SECURITY CLASS *(This Report)* Unclassified	21. NO. OF PAGES 401
	20. SECURITY CLASS *(This page)* Unclassified	22. PRICE

PB81-234239

July 1980

ENVIRONMENTAL AND ECONOMIC COMPARISON OF ADVANCED PROCESSES FOR CONVERSION OF COAL AND BIOMASS INTO CLEAN ENERGY

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FOREWORD

When energy and material resources are extracted, processed, converted, and used, the related pollutional impacts on our environment and even on our health often require that new and increasingly more efficient pollution control methods be used. The Industrial Environmental Research Laboratory — Cincinnati (IERL-Ci) assists in developing and demonstrating new and improved methodologies that will meet these needs both efficiently and economically.

The subject of this report is an environmental and economic comparison of various processes for converting biomass and coal into clean energy. The information contained herein will be of interest to those involved in biomass and coal conversion research and development programs, and to those involved in the evaluation of alternative clean energy sources. Inquiries and comments regarding the report should be directed to the Alternate Energy Sources Branch, Energy Pollution Control Division.

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EXECUTIVE SUMMARY

This report presents the results of three environmental and economic comparisons of biomass and coal conversion into clean energy. The study was initiated to help develop priorities for assessing conversion technologies capable of producing clean energy from biomass and coal resources. Electric power, synthetic pipeline gas (SPG), and synthetic fuel oil were chosen as representative clean energy products which can be produced from both biomass and coal. Representative coal conversion technologies were to serve as base cases to which biomass conversion technologies were to be compared. Three regional scenarios, each with a biomass-coal plant pair, were selected from a number of possible candidates. Conceptual designs of commercial-scale plants were compared in these regional scenarios:

- A 50 MWe wood-fired power plant versus a 500 MWe coal-fired power plant in the South Central U.S.
- A 7 MM SCFD (6.7 billion Btu/day) biogas plant (anaerobic digestion of wheat straw and manure) versus a 274 MM SCFD (250 billion Btu/day) high-Btu gasification plant (steam-oxygen HYGAS^R) in the Midwest
- A 1764 BPD wood-to-oil liquefaction plant versus a 66,856 BPD coal liquefaction plant (H-Coal^R) in the Northeast

In the scenarios, biomass residue is collected locally from forestland (chipped forest residue), from farmland (wheat straw), and from feedlots (cattle manure). Coal is strip-mined in the first two scenarios and deep-mined in the third. As plant feedstocks, the biomass materials have lower sulfur and ash contents, lower heating values, and lower bulk densities (except manure) than coal.

The plant capacities chosen are representative of commercial scales being proposed for biomass residue and coal conversion. The disparity in biomass-coal plant capacities is almost inherent; hence the higher capacity coal conversion plants have a distinct economy-of-scale advantage. The direct combustion and the liquefaction processes for biomass conversion are similar to their coal conversion counterparts. A biological conversion process, anaerobic digestion, is compared with a thermal conversion process, steam-oxygen gasification. Estimated plant thermal efficiencies (based on net product output) are compared below:

	Power	SPG	Fuel Oil
Biomass conversion	21.6%	31.9%	42.1%
Coal conversion	35.1%	69.7%	65.5%

It is apparent that these three biomass processes have relatively low conversion efficiencies. In the wood conversion processes, the feedstock properties are a disadvantage — low heating values (high moisture and oxygen contents) and low bulk densities mean that more material must be handled per unit of energy content than for coal. Energy consumption and losses are high. The anaerobic digestion process suffers from a low methane production rate and incomplete biomass conversion. This process does yield a digester residue that may be a valuable byproduct if it can be used as an animal feed.

Improvements in conversion efficiencies are important if these particular biomass processes are to be competitive with the coal processes. Worthwhile ideas for improving feedstock properties (preprocessing of biomass) should be given attention, as such ideas could lead to increased process conversion efficiencies.

Economic comparisons of the biomass and coal conversion concepts are presented in Figures 1, 2, and 3 for utility and private financial methods, using the ERDA-AGA Cost Guidelines. These figures illustrate that the biomass-derived energy products are about 50 percent (power) to 300 percent (SPG) more expensive to produce than the corresponding coal-derived products from much larger conversion plants. Synthetic fuel oil from wood liquefaction is about 2.5 times more costly than oil from the H-Coal process. In these scenarios at least, the economic disparities result from a combination of less desirable feedstock properties, smaller biomass plant capacities, and lower process conversion efficiencies. In many economic situations, both direct-fired plants would produce electric power more cheaply than it could be produced in conventional power plants firing any of the four synthetic fuels.

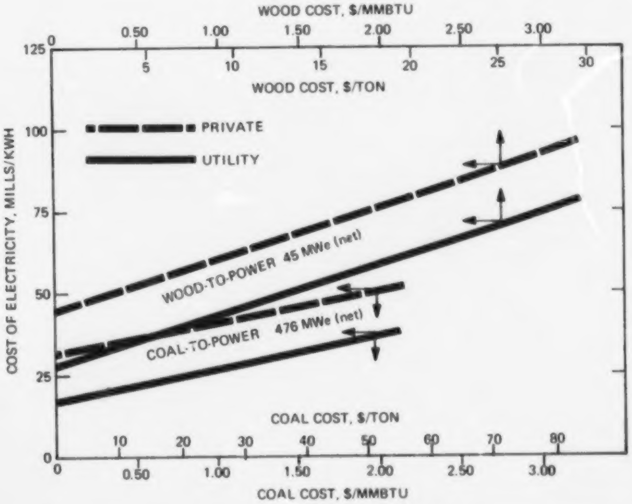

Figure 1. Economic comparisons of wood and coal to power.

Figure 1 shows that the cost of electricity from a wood-fired plant is not competitive with that from a large coal-fired generating station if wood and coal prices are about the same on a $/MM Btu basis. For a high coal

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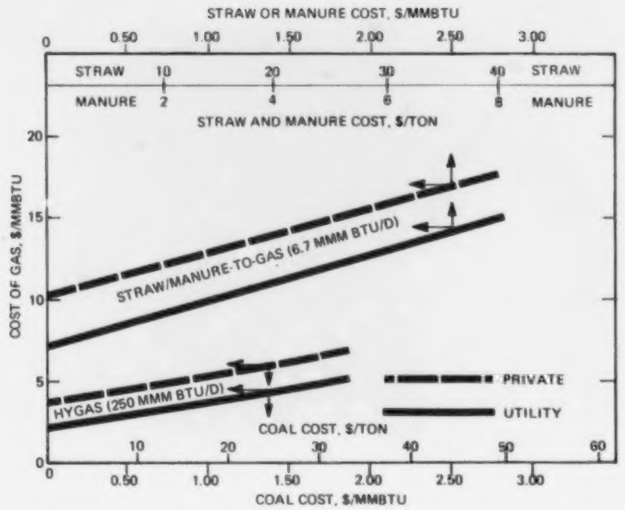

Figure 2. Economic comparison of straw/manure and coal to SPG.

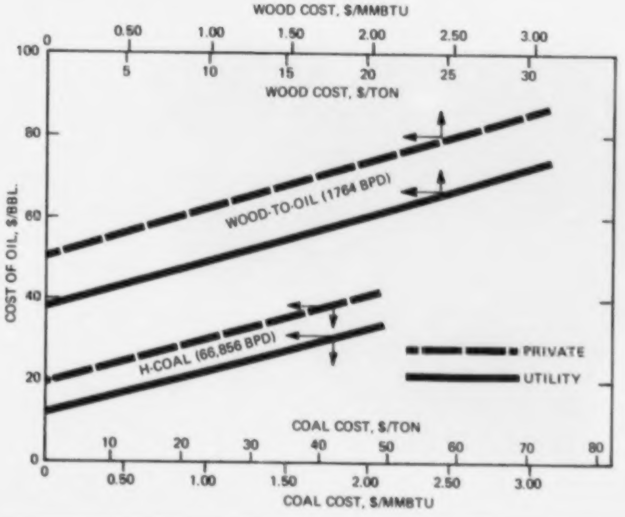

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Figure 3. Economic comparison of wood and coal to fuel oil.

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cost/low wood cost scenario, a small wood-fired plant could be economic as evidenced by existing power boilers burning wood wastes in many pulp and paper mills in the Northeast.

The biomass-derived synthetic gas and oil are just not close to being competitive with the coal derived synthetic fuels, as Figures 2 and 3 illustrate.

Pollution control costs will be high for the large coal conversion plants, probably 5 to 10 percent of the total plant capital costs. These large expenditures, however, do not shift the economic advantage to biomass conversion, as the foregoing figures show.

Environmental impacts of plant construction and operation were considered separately from impacts of resource collection. Resources consumed by the plants and emissions of conventional pollutants were estimated for each biomass and coal conversion plant, and then comparisons were made on a relative (energy output) basis. None of the three biomass conversion plants appears to have an overall environmental advantage over its coal conversion plant counterpart on the relative comparison basis. This environmental standoff is partly due to the extensive pollution controls used in the coal conversion plants which reduce conventional pollutant emissions to about the same overall levels as those from biomass conversion. The potential for generation and release of toxic or hazardous substances (priority pollutants) cannot be assessed adequately at this time because much of the information has not been developed yet.

Biomass residue collection should entail considerably fewer adverse consequences on the environment than deep-mining or strip-mining coal resources. Forest residue or wheat straw collection activities will affect much more land area than coal mining, but little environmental damage should occur if collection activities are managed properly. Unlike coal, the biomass resources are renewable and some environmental credit is deserved for their utilization. If the plant impacts and the collection impacts are considered together, biomass conversion in these scenarios may be preferable from an overall environmental impact viewpoint.

Major conclusions reached from these three biomass-coal comparisons are:

- The coal conversion plants have considerably higher thermal efficiencies than their biomass counterparts

- The biomass residues have the advantage of low sulfur and ash contents, but their low bulk densities and low energy contents are distinct disadvantages with respect to coal as a plant feedstock

- Biomass-derived electric power, SPG, and synthetic fuel oil are more expensive to produce than the corresponding coal-derived clean energy products from the large-scale conversion plants

- Pollution control costs for the coal conversion plants are high, but have little impact on the relative economics of coal versus biomass conversion

- The anaerobic digestion and wood liquefaction processes are not promising routes to low cost synthetic fuels in view of the superior HYGAS and H-Coal process economics

- In certain localities, power generation from wood may be economically competitive with power generation from coal if the coal:wood price ratio is high enough

- The small biomass conversion plants do not appear to have an overall environmental advantage over their coal conversion plant counterparts on a relative basis; however, more and better quantitative emission data need to be developed in order to better assess the probable impacts of both the biomass and coal conversion technologies

- Managed properly, biomass residue collection should have less severe environmental impacts than coal mining, even though much more land area would be affected by residue collection

From these comparisons, it is evident that the coal conversion processes are more likely to become major routes to clean fuels than these biomass conversion processes, primarily because of better economics. Other biomass feedstock/conversion process/energy product scenarios could prove to be more favorable in this type of biomass-coal comparison. A combination of three factors is desirable:

- A relatively low-priced biomass feed material

- A process that has a relatively high conversion efficiency

- A higher-priced product than fuel oil or fuel gas

Steam and power production from low-cost residues and co-firing of wood and fossil fuels appear to be promising ways of using biomass resources in a number of localities in the U.S. Biomass conversion into more valuable products (chemicals, fertilizers, animal feeds) should also be a promising area of study.

Both biomass and coal conversion would have adverse environmental impacts, and there is continuing need to better define the likely impacts of resource collection, conversion, and product usage.

The coal conversion plants need to be large in order to produce competitively priced clean energy. If the coal conversion plants could be scaled-down to the same low capacities as their biomass plant counterparts, it is likely that the coal-derived energy products would be more costly than the respective biomass-derived products. In some localized scenarios, biomass conversion could have an economic advantage over coal conversion on a small scale.

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ABBREVIATIONS

ac = acre
ACFM = actual cubic feet per minute
API = American Petroleum Institute
bbl = barrels
BPD = barrels per day
BPSD = barrels per stream day
BOD = biochemical oxygen demand (5-day)
bhp = brake horsepower
Btu = British thermal unit
cfm = cubic feet per minute
CFD = cubic feet per day
CFY = cubic feet per year
CO = carbon monoxide
CO_2 = carbon dioxide
COS = carbonyl sulfide
CPI = corrugated plate interceptor
cu ft = cubic feet
dSCF = dry standard cubic foot
ft = feet
FGD = flue gas desulfurization
g = grams
gal = gallons
gpm = gallons per minute
gr = grains
ha = hectares
HC = hydrocarbons
HHV = higher heating value
hp = horsepower
Hz = Hertz
H_2S = hydrogen sulfide
in. = inches
in. Hga = inches of mercury absolute
JTU = Jackson turbidity units
kg = kilograms
kV = kilovolts
kVA = kilovolt amperes
kW = kilowatts
kWh = kilowatt hours
lb = pounds
LHV = lower heating value
LTPSD = long tons per stream day
M = thousand
MM = million
MMM = billion
mg/l = milligrams per liter
MLVSS = mixed liquor volatile suspended solids
mph = miles per hour
MPH = moles per hour
MPN = most probable number
MT = metric tons
MVA = megavolt amperes
MW = megawatts
MWe = megawatts electrical
MWt = megawatts thermal
NPDES = National Pollutant Discharge Elimination System
NO_x = nitrogen oxides
NSPS = new source performance standards
pf = power factor
PM = particulate matter
ppmv = parts per million by volume
psia = pounds per square inch absolute
psig = pounds per square inch gauge
RO = reverse osmosis
SCA = specific collection area
SCFD = standard cubic feet per day
sq ft = square feet
SO_x = sulfur oxides
S.P. = static pressure
STPSD = short tons per stream day
TDH = total dynamic head
TDS = total dissolved solids
tpd = tons per day
tph = tons per hour
TSS = total suspended solids
TTD = terminal temperature difference
VS = volatile solids
wg = water gauge

UNIT CONVERSIONS TO S.I.

English Units	SI Units
1 acre (ac)	4046.86 meter^2
1 acre foot	1233.48 meter^2
1 atmosphere (atm)	101.325 kilopascal
1 barrel (bbl)	0.15899 meter^3
1 brake horsepower (bhp)	0.7457 kilowatts
1 British thermal unit (Btu)	1.05435 kilojoules
1 Btu/hr	0.29288 watts
1 Btu/pound (lb)	2.3244 joules/gram
1 Btu/lb mole	2.3244 joules/mole
1 Btu/standard cubic foot (SCF)	37.320 kilojoules/meter^3
1 cubic foot (cu ft)	0.02832 meter^3
1 cubic foot per hour (CFH)	7.8667 x 10^{-6} meter^3/second
1 foot	0.3048 meter
1 gallon (U.S.)	3.785 x 10^{-3} meter^3
1 gallon per minute	6.3089 x 10^{-5} meter^3/sec
1 horsepower (hp)	0.7457 kilowatts
1 inch of mercury (60°F)	3,376.85 newton/meter^2
1 kilowatt hour (kWh)	3600 kilojoules
1 inch of water (60°F)	248.84 newton/meter^2
1 pound (lb)	0.45359 kilograms
1 lb/cu ft	16.0185 kilograms/meter^3
1 lb/hr	0.12600 grams/second
1 lb/million (MM) Btu	4.3021 x 10^{-7} kilograms/kilojoule
1 lb mole/hr	0.12600 gram mole/second
1 mile (U.S. statute)	1609.344 meter
1 pound per sq in. absolute (psia)	6.89476 kilopascal
1 standard cubic foot per minute (SCFM)	4.7200 x 10^{-4} meter^3/second
1 short ton per day (STPD)	0.10500 kilograms/second
1 ton (short)	907.185 kilograms
1 ton (long)	1016.047 kilograms
1 ton per hour (tph)	0.25200 kilograms/sec
1 ¢/lb	2.2046 ¢/kilogram
1 ¢/M gallons	0.26417 ¢/meter^3
1 $/MM Btu	9.4845 x 10^{-7} $/kilojoule
1 $/ton	1.1023 x 10^{-3} $/kilogram
1 mill/kWh	2.778 x 10^{-5} ¢/kilojoule

ACKNOWLEDGMENTS

The authors wish to acknowledge the Project Officer, Mr. Thomas J. Powers of the Energy Systems Environmental Control Division, IERL, Cincinnati for his continued support and guidance throughout this study. We would also like to acknowledge the helpful comments and suggestions concerning coal conversion by Mr. T. Kelley Janes, Branch Chief, Fuels Process Branch, IERL, Research Triangle Park.

The authors especially wish to thank Professor William J. Oswald and Professor Theodore Vermeulen, both of the University of California, Berkeley, for their service as voluntary reviewers of the draft final report. Their comments and suggestions were very useful in the preparation of this final report.

SECTION 1

INTRODUCTION

OBJECTIVES OF THE STUDY

The United States has enormous quantities of both biomass and coal. A hundred years ago, the U.S. obtained about 75 percent of its energy from wood (2.4 quads — or about 3 percent of current energy consumed)(1). Later, coal provided the major source of energy in the U.S. before petroleum and natural gas supplies became abundant. Today, coal accounts for less than 19 percent of the U.S. energy consumption, but constitutes more than 90 percent of the total national resources of coal, petroleum, and natural gas(2). Both biomass and coal are likely to be major energy and chemical feedstock sources in the future if economical conversion processes can be developed. But coal, rather than biomass, will probably predominate in the next 20 years.

Intrinsically, biomass materials are "cleaner" sources of energy than coal because of their relatively low sulfur and ash contents. Coal conversion processes will generally require more extensive control technology to produce clean-energy forms and to prevent the release of pollutants in damaging quantities to the environment. The environmental controls needed for the conversion of coal into clean-energy forms are costly. To aid in developing priorities on the specific conversion technologies to be assessed, it is desirable to evaluate coal-based technologies against other technologies capable of producing similar clean-energy forms from nonfossil-based raw materials. Conversion of renewable resources such as biomass residues is a specific alternative to be considered.

The major objectives of this study were to provide both environmental and economic assessments to compare the conversion of biomass and coal into clean energy. Specific emphasis was to be placed upon the analysis of the applicability of existing biomass conversion processes, the technology requirements, the costs of pollution control, and the costs of clean energy production compared to coal-based technology. Pollutant emissions and the environmental impacts of biomass conversion were also to be evaluated.

GROUNDRULES AND METHODOLOGY

To make environmental and economic comparisons of biomass versus coal, several factors needed unbiased consideration:

- Conversion technologies and state of development
- Type, location, and availability of resources

- Forms of clean energy and plant sizes
- Environmental regulations
- Economic bases and time of plant implementation

A wholly satisfactory basis was not found. It was felt that only three biomass-coal comparisons could be covered adequately in this study. In view of this, a range of possibilities was deliberately developed for the three comparisons:

- Three different conversion technologies in different states of development — direct combustion, gasification, liquefaction
- Three regional locations
- Three biomass types
- Three coal types
- Three clean energy products — electric power, synthetic pipeline gas, synthetic fuel oil

This list includes three different major energy forms for which coal conversion technologies exist and which could be used as bases for comparison with appropriate biomass conversion technologies. A methanol or ethanol fuel could also have been chosen as a representative clean energy form.

Factors that proved to be difficult to normalize included plant sizes, environmental regulations, and economic evaluation bases because of the differing states of process development, the unknown future implementation periods, and the future cost of feedstocks. Difficulties encountered in the comparisons are discussed in subsequent sections.

A recent Battelle report, which outlined six regional scenarios, provided the basis for preliminary selection of the biomass conversion scenarios and processes(3). Other sources of information were also used in selecting candidate regions, resources, and conversion processes.

On the biomass conversion side, conversion processes and economic evaluations were limited to those in at least the conceptual design stage and for which commercial-scale plant economic data were available to the public.

General groundrules and methodology established for selection and comparison of the specific processes were:

- Site characteristics
    - Each plant site will be favorable for the particular conversion process; sufficient land is available; resources are adequate; there is a demand for the product in the region
    - A general description of each plant site will be given; the sites will be hypothetical (not identified)

- Feedstocks
  - Available quantities will be cited; resources must be sufficient to support the plant over its operating life
  - Seasonal variations will be considered
  - A single feedstock composition will be used for the plant conceptual design
  - Feedstock collection and transport will be described
  - Costs of feedstock delivered to the plant will be estimated
- Plant and conversion processes
  - Each plant will be of the largest practical capacity, with due consideration to feedstock availability, conversion equipment of commercial size, and demand for the product in the region
  - Major products will be comparable in form and of a quality usable offsite as an energy supply
  - Conversion details will be based on published information, discussions with process developers, and engineering judgment
  - The biomass-coal pairs will have the same stream or load factors and the same plant operating lives
  - Auxiliary facilities for each plant will be identified for cost estimating purposes; however, offsite product distribution systems will be excluded
  - Environmental controls for each plant will be identified and will meet applicable new source standards or will be based on best available technology
- Environmental emissions and impacts
  - Principal resources committed to each plant will be estimated and compared on a normalized (product output) basis
  - Air, water, and solid waste pollutant emissions from each plant will be estimated, if possible
  - Implications of federal regulations (air, water, toxic materials, hazardous waste) will be considered

    - Environmental impacts of each plant will be described based on resources committed, environmental emissions and the general characteristics of the site; an environmental matrix will be used to compare the impacts of each biomass-coal pair

    - Impacts of feedstock procurement will be described very qualitatively for each conversion case and biomass-coal procurement impacts will be compared in matrix form

- Cost estimates and economics (see Appendix C for cost information methods)

    - Capital and operating costs will be based on first quarter 1978 wage and price levels for all plants

    - Pollution control costs will be discussed

    - The biomass and coal conversion economics will be compared on a utility and a private financing basis with feedstock cost as a sensitivity parameter

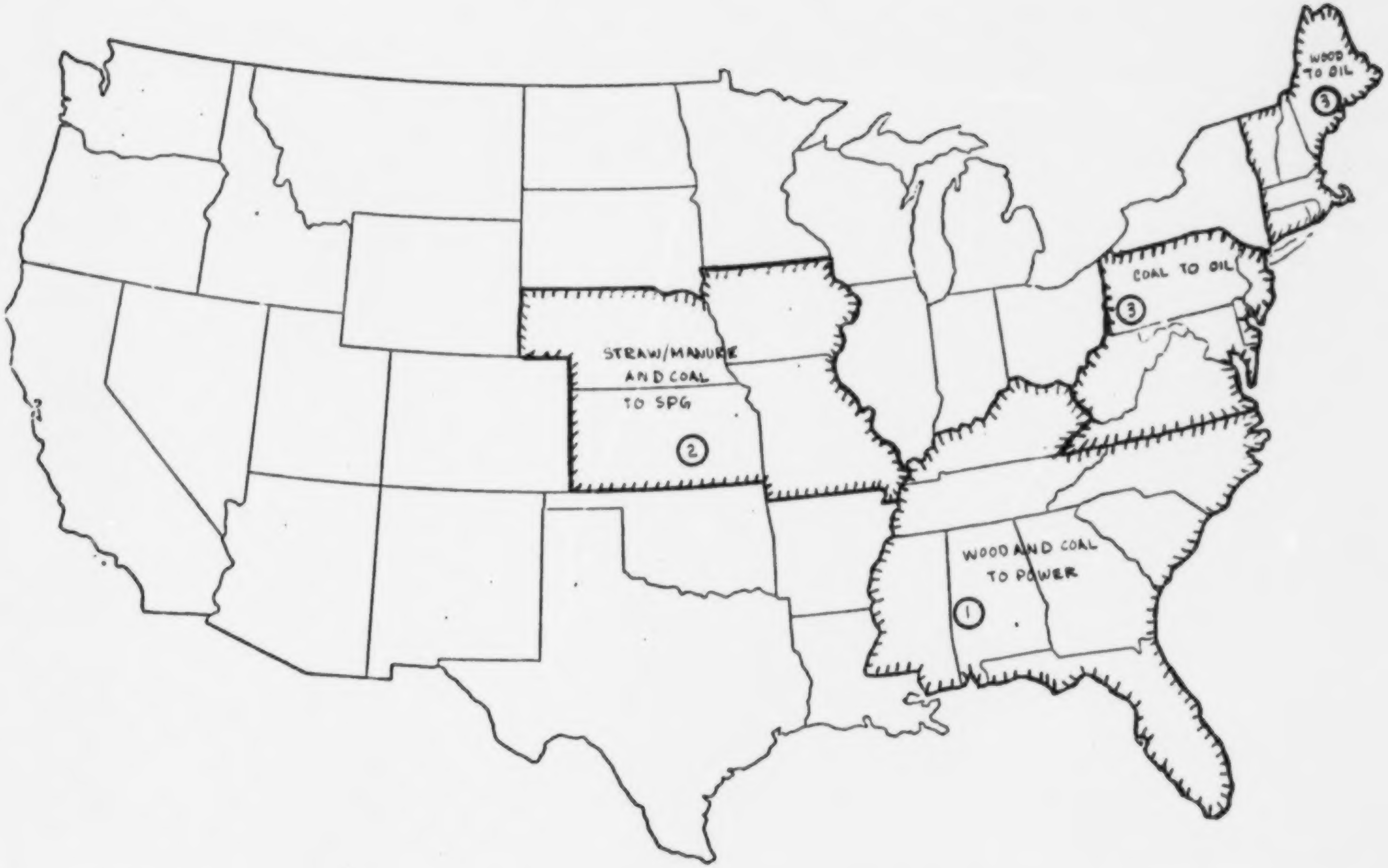
    - A simplified production (break-even) cost will also be given for the biomass conversion plants

Figure 4 shows the biomass-coal regions selected for the scenarios. Table 1 summarizes the three pairs of plants selected for comparison.

The basic approach was to attempt to define reasonable commercial-scale biomass conversion processes, estimate their costs, and estimate their major environmental emissions and impacts — given the limited states of process development in two of the three processes. The disparities in biomass and coal-plant capacities are primarily the result of limitations on the biomass side. Types of limitations generally include biomass residue availabilities, onsite storage and handling difficulties, and, to a lesser extent, process equipment limitations or complexities. It would be unreasonable to scale down the coal conversion plants to match the biomass conversion plant capacities.

The HYGAS^R and H-Coal^R conversion facilities were designed and their cost estimated by others (5, 6, 7), and no comments are made on their technical soundness or cost estimations. They are used as base references for the biomass-coal comparisons. The ERDA-AGA gas cost guidelines (8) were used for comparing the relative economics of biomass and coal conversion on a consistent basis.

Published environmental emission data were lacking in many areas for both biomass and coal conversion processes. Emission estimates in this study were limited primarily to conventional pollutants. The emissions and impacts presented are incomplete and somewhat speculative. The objective was to estimate and compare major impacts anticipated from construction and operation of the hypothetical conversion facilities.



WOOD TO OIL
③
COAL TO OIL
③
STRAW/MANURE AND COAL TO SPG
②
WOOD AND COAL TO POWER
①

Figure 4. Biomass and coal scenario regions.

TABLE 1. SELECTED BIOMASS-COAL PROCESS COMPARISONS

Major Product	Uses	Feedstock	Conversion Process	Plant Size	Plant Location
Electric Power	Local utility supply	Forest residue	Wood-fired boiler – steam turbine generator	1870 TPD feed 45 MWe output	South Central US (Alabama, Mississippi)
Electric Power	Regional utility supply	Eastern bituminous, strip-mined, 1.4% sulfur	Pulverized coal-fired boiler – steam turbine generator	4190 TPD feed 476 MWe output	South Central US (Alabama, Mississippi)
Synthetic Pipeline Gas (SPG)	Local utility gas supply	Wheat straw and cattle manure	Anaerobic digestion and CO_2 removal (upgrading)	2000 TPD feed 6.7 MMM Btu/day product	Midwest (Kansas, Nebraska)
Synthetic Pipeline Gas	Regional utility gas supply	Western subbituminous, strip-mined, 0.5% sulfur	IGT-HYGAS^R (steam-oxygen) process plus methanation	20,472 TPD feed 250 MMM Btu/day product	Midwest (Kansas, Nebraska)
Heavy Fuel Oil	Low sulfur boiler fuel	Forest residue	Catalytic liquefaction (PERC) process	1965 TPD feed 1764 BPD product oil	Northeast (Maine, Vermont)
Heavy Fuel Oil and Naphtha	Low sulfur boiler fuel, refinery feedstocks	Eastern bituminous, deep-mined, 4.4% sulfur	HRI H-Coal^R process (fuel oil mode)	27,836 TPD feed 66,856 BPD products	Northeast (Pennsylvania, West Virginia)

Additionally, there is a general lack of environmental regulations or guidelines specifically applicable to new conversion processes for producing synthetic fuels. Table 2 lists some of the federal legislation which may have an impact on air, water, and solid waste emissions from these hypothetical conversion plants. For the steam-electric generating source category, there are published new source performance standards (NSPS) that would be applicable to the wood and coal-to-power plants. In the electric power scenarios, unpublished "draft" NSPS for particulate matter, sulfur oxides (SO_x), and nitrogen oxides (NO_x) listed in Table 2 are assumed to apply. These unpublished draft standards would require percentage emission reductions in addition to maximum limits. For the other conversion scenarios, the environmental control technologies assumed may or may not be sufficient to meet future requirements established under the listed legislation. In subsequent sections of the report, environmental uncertainties or potential problem areas are identified.

Section 2 summarizes the biomass and coal conversion scenarios, their economics and anticipated environmental impacts, and conclusions and recommendations for future studies.

Sections 3, 4, and 5 present the details of the three biomass-coal conversion scenarios. In Section 6, each biomass and coal conversion pair is compared on an economic and environmental impact basis. The appendices contain plant equipment lists, a discussion of feedstock availability, and a summary of the cost estimating and economic evaluation methods used in this study.

TABLE 2. SUMMARY OF POTENTIALLY APPLICABLE FEDERAL ENVIRONMENTAL LEGISLATION

Environmental Emission Category	Public Law, Regulation or Guideline	General Significance or Applicability to Biomass-Coal Conversion
Air Pollutant Emissions (PM, SO_x, NO_x, CO, Nonmethane Hydrocarbons)	Clean Air Act Amendments of 1977, PL 95-190	Prevention of significant deterioration — applicable to major new stationary sources with potential emissions $\geq$100 tons/yr; BAT may be required in clean air areas, emission offsets may be required in nonattainment areas
Air Pollutant Emission Standards (PM, Opacity, SO_x, NO_x)	"Draft" NSPS for steam-electric generating, 40 CFR 60, Subpart D: • PM $\leq$0.03 lb/MM Btu input and 99% reduction of uncontrolled emissions • Opacity $\leq$10% (6-minute average) • SO_x $\leq$1.2 lb SO_2/MM Btu input and 90% reduction of uncontrolled emissions ($\leq$0.2 lb/MM Btu — no reduction required) • NO_x $\leq$0.6 lb NO_2/MM Btu input and 65% reduction of uncontrolled emissions	Assumed to be applicable to wood and coal-fired power plant scenario, instead of current NSPS's which have no requirements for percentage reduction of uncontrolled emissions
Sulfur Emissions	Final NSPS for petroleum refining, 40 CFR 60, Subpart J: • Fuel gas (combustion) $\leq$0.1 gr H_2S/dSCF • Claus plant tail gas $\leq$250 ppmv SO_2/dSCF (after incineration) or $\leq$300 ppmv reduced sulfur compounds and $\leq$100 ppmv H_2S (as SO_2)/dSCF (no incineration)	Standards for fuel gas combustion and sulfur recovery plants with oxidation or reduction control systems may be applied in the future to similar units in coal conversion facilities
Air Pollutants - Hazardous	The Clean Air Act of 1970, Section 112	Emission standards or control technology may be established for identified hazardous air pollutants, e.g., mercury, beryllium, benzene
Water Pollutant Emissions	The Federal Water Pollution Control Act of 1972, PL 92-500: Effluent Guidelines and Standards for Steam-Electric Power Generating (40CFR423)	NPDES discharge permit required — sets allowable emission rates, best available technology (BAT) required for new sources; no standards established yet for biomass or coal conversion as point source categories
Water Pollutant Emissions	The Clean Water Act of 1977, PL 95-217	Requires implementation of BAT by July 1984 for existing point source categories, focuses on control of priority pollutants (potential toxic substances); potential future application to biomass and coal conversion effluents
Solid Wastes	The Resource Conservation and Recovery Act of 1976, PL 94-580	Criteria to be developed for identifying hazardous substances for purposes of hazardous waste management — potential impact on biomass and coal conversion waste disposal
Toxic Substances	The Toxic Substances Control Act, PL 94-469	Identify and evaluate potential hazards in chemical substances; regulate the production use, distribution and disposal of toxic substances

SECTION 2

SUMMARY AND RECOMMENDATIONS

This section summarizes the three biomass-coal scenarios through a comparison of the conversion processes, their economics as of first quarter 1978, and their relative environmental impacts. Conclusions and recommendations are presented at the end of this section.

Three scenarios were used to depict conversion of renewable (biomass) and nonrenewable (coal) resources into forms of clean energy in regional contexts — wood and coal to power in the south central region, straw/manure and coal to synthetic pipeline gas in the midwest, and wood and coal to (synthetic) fuel oil in the northeast. This regionalization primarily affects the type and characteristics of the plant feedstock materials, but the effects of regional location on conversion processes, economics, and environmental impacts were considered.

PROCESS CONVERSION SUMMARIES

Wood and Coal to Power

Table 3 compares major process factors of the 50 MWe wood-fired power plant and the 500 MWe coal-fired power plant. Both are assumed to be single unit installations. The order-of-magnitude disparity in plant capacity, by itself, has relatively little effect on the relative process conversion efficiencies.

The principal biomass-coal process differences are in feed preparation (none versus pulverization), in the nonreheat versus reheat steam cycle, and in requirements for flue gas cleanup (no sulfur removal versus 90 percent sulfur removal). The higher sulfur and ash contents of the coal (versus wood), along with more expensive flue gas cleanup, result in the large relative difference in solid waste generation.

The gross thermal efficiency of the wood-fired plant is about one-third lower than that of the coal-fired plant. A significant portion of this difference is attributable to the high moisture content of the wood (50 percent), which results in a low boiler efficiency. It should be noted that the thermal efficiency could be improved by using drier fuel and a more efficient (and costly) steam cycle.

Straw/Manure and Coal to SPG

Table 4 compares process features of the 6.66 billion (MMM) Btu/day biogas plant with the 250 MMM Btu/day coal gasification plant based on the IGT Steam-Oxygen HYGAS Process (5). Feed preparation is somewhat similar. The conversion

9

TABLE 3. SUMMARY COMPARISON OF WOOD AND COAL TO POWER CONVERSION PROCESSES

Process Elements	Wood-to-Power 45 MWe (net)	Coal-to-Power 476 MWe (net)
Plant Capacity (gross output)	50,010 kW	504,300 kW
Product Output — Electric Power	45,080 kW/115 kV	476,000 kW/345 kV
Feedstock	Forest residue - 4,565 Btu/lb, <0.01% sulfur	Bituminous coal - 13,033 Btu/lb, 1.44% sulfur
Onsite Storage	56,000 tons, 30 days	264,600 tons, 60 days dead and 3 days live
Feed Preparation	None - received as chips	Pulverization
Feed Input Rate	78 tph	175 tph
Conversion Process	Tangentially-fired furnace with traveling grate, drum-type boiler with superheater and economizer	Tangentially-fired, balance draft furnace, controlled circulation boiler with superheater and economizer
Steam Conditions (at throttle)	470,000 lb/hr/1250 psia/900°F	3.37 MM lb/hr/2411 psia/1,000°F/1,000°F reheat
Steam Turbine	50,000 kW, single flow, single case condensing	553,000 kW, tandem compound, 4-flow, single reheat condensing
Turbine Generator	60,000 kW, H_2-cooled 13.8 kV, 3ϕ, 60 Hz, 0.9 pf	590 MVA, H_2-cooled 22 kV, 3ϕ, 60 Hz, 0.95 pf

(Continued)

TABLE 3 (Continued)

Process Elements	Wood-to-Power 45 MWe (net)	Coal-to-Power 476 MWe (net)
Surface Condenser	1-shell, 2-pass, 50,000 sq ft, 6°F TTD, 2 inches Hga	2-shell, 2-pass, 234,000 sq ft 6°F TTD, 2.5 inches Hga
Feedwater Heating	3 stages (1 open), drain feed forward	7 stages (1 open), drain feed backward
Flue Gas Cleanup	Electrostatic precipitator (ESP) 99+ % efficiency, 330 SCA	ESP (99% efficiency, 340 SCA)+lime slurry FGD system (90% SO_2 removal) + 50°F reheat
Heat Dissipation	4-cell induced draft cooling tower, 333 MM Btu/hr, 15°F cooling range	Two 8-cell induced draft towers, 2350 MM Btu/hr, 30°F cooling range
Solid Waste Disposal	1,430 tons per year - onsite landfill	215,600 tons per year - onsite landfill
Boiler Efficiency	70%	89.7%
Gross Thermal Efficiency	24.0%	37.8%
Overall Plant Thermal Efficiency	21.6%	35.1%*
Plant Heat Rate (net)	15,790 Btu/kWh	9,727 Btu/kWh*
Plant Load Factor	69.9% (255 days/yr)	69.9% (255 days/yr)
Plant Operating Life	30 years	30 years

*Includes 78 MM Btu/hr natural gas for flue gas reheat; if excluded, the above values would be 35.7% and 9,563 Btu/kWh.

TABLE 4. SUMMARY COMPARISON OF STRAW/MANURE AND COAL TO SPG CONVERSION PROCESSES

Process Elements	Straw/Manure-to-SPG 7 MM SCFD (net)	Coal-to-SPG (HYGAS) 274 MM SCFD (net)
Plant Capacity	6.66 MMM Btu/day	250 MMM Btu/day
Product	SPG-7.01 MM SCFD at 950 Btu/SCF, 305 psig	SPG — 273.7 MMSCFD at 915 Btu/SCF, 1010 psig
Feedstocks	Wheat straw — 8548 Btu/lb, 0.176% sulfur Cattle manure — 1225 Btu/lb, 0.045% sulfur	Western subbituminous coal — 8,800 Btu/lb, 0.51% sulfur
Onsite Storage	Straw — 60,000 tons, 60 days Manure — 15,000 tons, 15 days	Coal — 1,515,000 tons, 14 days live, 60 days dead
Feed Input Rate	Straw — 1000 tpd Manure — 1000 tpd	Coal — 20,472 tpd
Feed Preparation	Straw — grind, pulp and slurry Manure — pulp and slurry	Wet grind, slurry, and preheat
Conversion Process	Single-stage anaerobic digestion, 10 day retention (1 train)	Steam — oxygen gasification (HYGAS) 600-1,850^{o}F, 1200 psig (2 trains)
Raw Gas Cleanup and Upgrading	Acid gas removal and dehydration (1 train)	Gas quench, shift conversion, acid gas removal, methanation and dehydration (2 trains)
Utility Generation	Process steam - raw and product gas heaters/boilers power - purchased	Process steam and power - process heat recovery and coal-fired boilers/turbine generators; oxygen - air separation plants
Flue Gas Cleanup	None required	Sulfur recovery via IFP Stackpol process

(Continued)

TABLE 4. (Continued)

Process Elements	Straw/Manure-to-SPG 7 MM SCFD (net)	Coal-to-SPG (HYGAS) 274 MM SCFD (net)
Acid Gas Cleanup	Incineration	Sulfur recovery via IFP Stackpol process
Byproduct Recovery	None	Sulfur 88.9 LTPD Ammonia 88.8 STPD Oil 4594 BPD
Heat Rejection	2-cell induced draft cooling tower, 25°F range 24 MM Btu/hr	Maximum air cooling 4-cell induced draft tower, 35°F range, 359 MM Btu/hr
Solid Waste Disposal	604,400 tons per year residue — returned to farmland, other buried onsite	785,200 tons per year ash-returned to mine, other buried onsite
Conversion Thermal Efficiency	33.3%	69.7%
Overall Thermal Efficiency	31.9*%	77.6**%
Plant Load Factor	90% (328.5 days/yr)	90% (328.5 days/yr)
Plant Operating Life	20 years	20 years

*Deduction for fuel equivalent of purchased electric power
**Credit for heat value of by-products

processes are totally different, but both produce medium-Btu raw gas. The biogas is upgraded by carbon dioxide removal versus the more extensive upgrading required for the gasifier raw product gas. Air pollution controls in the HYGAS plant are considerably more extensive than in the biogas plant. Some oil, sulfur, and ammonia, however, are recovered as salable byproducts of gas cleanup. The biogas plant produces proportionately more solid waste for disposal, partially a result of the relatively low conversion of straw and manure solids to gas. The use of digester residue as an animal feed is being actively investigated by process developers. Instead of being disposed of as waste, this residue may ultimately be the major salable product of a biogas plant.

The conversion efficiency of feed energy to SPG in the biogas plant is about one-half the conversion efficiency of the HYGAS plant. Not enough is known about the mechanism of methane production by anaerobic digestion to predict whether a significant improvement in conversion efficiency can be achieved. A more optimistic estimate of straw and manure conversion to methane could have been made. An overall thermal efficiency of 40 percent would still be poor in comparison with the coal gasification efficiency.

Wood and Coal to Synthetic Fuel Oil

The wood and coal liquefaction processes have a large difference in plant capacity, but this difference does not greatly affect the relative process efficiencies. The feed preparation and liquefaction processes are similar. Table 5 provides a process comparison. The H-Coal process has a very complex product separation and recovery system, producing naphtha as well as heavy fuel oil. A heavy residuum from liquefaction is gasified to produce hydrogen (reducing) gas in the H-Coal process. Reducing gas for wood liquefaction is produced by partial pyrolysis of a separate wood feed stream. Both conversion plants have air separation plants to provide high purity oxygen. Coal liquefaction produces enough fuel gas to generate the plants' electric power requirements in power boilers, whereas electric power is assumed to be purchased in the wood liquefaction case. (Onsite power generation could be provided with a wood-fired power boiler.) Sulfur, ammonia, and phenols are recovered as byproducts from cleanup of various gas and aqueous streams in coal liquefaction. Few or no byproducts are produced in the wood liquefaction process. Unreacted feed solids (mainly ash) are the major process solid wastes generated in both liquefaction plants.

The thermal conversion efficiency of wood-to-oil is about 20 percent lower than that for the H-Coal process on a simple Btu basis. If the wood fuel equivalent (say, 15,500 Btu/kWh) of purchased electric power is used, the wood-to-oil thermal efficiency drops by 20 percent. An improvement in thermal efficiency would result from a significant reduction in the carbon monoxide/hydrogen gas generation requirements.

Process Summary

For each biomass-coal pair, the coal conversion process appears to enjoy a significantly higher overall thermal efficiency. Efficiencies of biomass conversion processes shown here are not considered to be optimistic, and improvements are likely as the processes become better developed. The relatively low

TABLE 5. SUMMARY COMPARISON OF WOOD AND COAL TO FUEL OIL CONVERSION PROCESSES

Process Elements	Wood-to-Fuel Oil 1764 BPD	Coal-to-Fuel Oil (H-Coal) 66,856 BPD
Plant Capacity	11.11 MMM Btu/day	417.6 MMM Btu/day
Products	Heavy fuel oil-1764 BPD, -31.8°API, 0.01% wt sulfur	Heavy fuel oil — 51,325 BPD, 1.8°API, 0.5% wt sulfur Naphtha — 15,531 BPD, 38.2°API, 0.02% wt sulfur
Feedstock	Forest residue — 4,977 Btu/lb, <0.01% wt sulfur	Bituminous coal — 11,900 Btu/lb, 4.45% wt sulfur
Onsite Storage	120,000 tons, 60 days	1,756,000 tons, 3 days live, 60 days dead
Feed Input Rate	1965 tpd	27,836 tpd
Feed Preparation	Grind, dry, and slurry with hot recycle oil	Grind, dry, and slurry with recycle oils and preheat
Conversion Process	Catalytic liquefaction with CO/H_2 gas, 650°F, 2500 psia — helical coil reactor & soak vessel (2 trains)	Catalytic liquefaction with H_2, 850°F, 3,000 psig — ebullated reactor (6 trains)
Product Recovery	Reactor product flash, solvent dilution, filtration, vacuum distillation and catalyst extraction (2 trains)	Reactor product vapor-liquid separation, slurry flash and hydroclone concentration, slurry stripping and solvent deashing, fractionation and naphtha stabilization (multiple trains)
Reduction Gas Generation	Wood pyrolysis (PUROX^R) scrubbing and acid gas removal (Benfield^R)	Heavy residuum gasification (Texaco Partial Oxidation), quench, shift conversion, acid gas removal (Selexol^R)

(Continued)

TABLE 5. (Continued)

Process Elements	Wood-to-Fuel Oil 1764 BPD	Coal-to-Fuel Oil (H-Coal) 66,856 BPD
Utility Generation	Oxygen — air separation plant Steam — wood-fired boiler Power — purchased	Oxygen — air separation plants process steam and power — process heat recovery and process fuel gas — fired boilers & turbogenerators
Byproduct Recovery	none	Sulfur (Claus) — 1052.2 LTPD Liquid ammonia (Chevron WWT) — 180.2 STPD Mixed phenols — 17.9 STPD
Heat Rejection	3-cell induced draft cooling tower, 30°F range, 90 MM Btu/hr	Air coolers and two 7-cell induced draft towers (process cooling), two 6-cell towers (power plant cooling), 35°F range
Solid Waste Disposal	~8,680 tons per year — buried in onsite landfill	~1,330,000 tons per year — offsite disposal in valley landfill
Conversion Thermal Efficiency	52.8% (HHV)	65.5% (LHV)
Overall Thermal Efficiency	42.1%* (HHV)	67.7%** (LHV)
Plant Load Factor	91.3% (8000 hr/yr)	91.3% (8000 hr/yr)
Plant Operating Life	20 years	20 years

*Deduction for fuel equivalent of purchased electric power
**Credit for heat value of byproducts

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heating values of the biomass feedstocks are a distinct disadvantage with respect to coal because more material must be handled per unit of energy content.

ECONOMIC COMPARISON

Capital and operating costs were estimated for each conceptual plant at first quarter 1978 wage and price levels. Estimates for the three biomass plants and the coal-fired power plant were based on Bechtel conceptual designs. Appendix C summarizes the cost estimating methods. Cost estimates by C.F. Braun & Co. (5) and Fluor Engineers and Constructors (6) for the HYGAS and H-Coal plants, respectively, were escalated to first quarter 1978 dollars.

Table 6 summarizes the capital and operating costs for the six conceptual conversion plants. The small capacities of the biomass conversion plants do result in cost penalties relative to the coal conversion plants since some economy of scale is lost.

TABLE 6. SUMMARY OF CAPITAL AND ANNUAL OPERATING COSTS*
BIOMASS AND COAL CONVERSION

Biomass and Coal Cases	Total Capital Cost $1,000,000	Annual Operating Cost** $1,000,000
476 MWe Coal-Fired Power Plant	384.0	14.8
45 MWe Wood-Fired Power Plant	54.2	2.2
250 MMM Btu/day Coal Gasification Plant	1,213.2	53.6
6.66 MMM Btu/day Biogas Plant	85.2	6.5
66,856 bbl/day Coal Liquefaction Plant	1,640.0	108.8
1,764 bbl/day Wood-to-Oil Plant	99.1	11.1

*First quarter 1978, price and wage levels
**Excluding feedstock costs

Capital investments for the power plants are about $1200/kW and $800/kW (net) for wood and coal, respectively. Annual operating expenses, excluding feedstock, are about 8 mills/kWh and 5 mills/kWh, respectively. Both the capital and operating costs for a several hundred megawatt wood-fired plant might be closer to the 500 MWe coal-fired plant, but plants in that size range are probably impractical at present.

For the synthetic pipeline gas plants, the capital investment per million Btu/day of output is about $12,800 for the biogas plant and about $4850 for

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the HYGAS plant. The escalation in Braun's 1976 HYGAS estimate was about 14 percent (5). Annual operating expenses, exluding feedstock, are about $2.97/MM Btu and $0.65/MM Btu, respectively. In this instance, it appears unlikely that a massive biogas (straw and manure) installation, even if practical, would be competitive with HYGAS.

The total capital cost for the H-Coal plant was escalated from Fluor's 1975 estimate (6). This 1978 investment is about $24,500 per barrel per day (BPD) of product or about $3930 per MM Btu/day. For wood liquefaction the investment is about $56,200/BPD or $8920 per MM Btu/day. Similarly, the annual operating expense, exluding feedstock, is about $4.90/bbl for H-Coal versus about $18.90/bbl for wood liquefaction. On a Btu basis, the operating expense comparison is about $0.78/MM Btu output versus $3.00/MM Btu. The comparison with synthetic fuel oil from coal is not very favorable.

The ERDA-AGA Gas Cost Guidelines were used to look at the conversion economics on a more formal and consistent basis (8). Both private and utility financing methods were used for each plant. Table 7 shows the annual plant feedstock inputs and product outputs. Tables 8 and 9 illustrate the effect of feedstock cost on the cost of clean energy products for the three pairs of plants.

The comparison indicates that wood-to-power at zero wood cost would be economically competitive with coal-to-power at about $25 per ton coal cost. The 28.5 mills/kWh base cost of electricity (utility financing) is not much higher than approximately 23 to 26 mills/kWh estimated by SRI (9) and Mitre (10) for approximately 50 MWe wood-fired plants with considerably higher thermal efficiencies.* It is also apparent that the cost of electricity is quite sensitive to wood costs, about 1.7 mills/kWh for each dollar per ton of wood. This is about 4.5 times the increase in the cost of electricity for each dollar per ton of coal increase for the larger coal-fired plant.

The cost of SPG from the biogas plant with either utility or private financing is several times what might be considered a reasonable (unregulated) gas cost today of, say, $2 to $2.50/MM Btu. Again the effect of feedstock cost on gas cost is large for the low capacity biogas plant. The effect is less dramatic for the large coal gasification plant. Other published estimates for SNG from biomass tend to be on the more optimistic side, mostly in the $3 to $4/MM Btu range (excluding feed costs) for anaerobic digestion and for gasification of various biomass materials (9, 10, 12). In this estimate at least, it does not appear that the biogas-derived SNG is competitive with coal-derived SNG from the HYGAS plant. Large economies of scale in the biogas plant are probably not possible either. If the digester residue were salable as an animal feed, then the plant economics could be much improved.

The economic comparison of wood and coal-to-oil indicates similar disparities in production costs and in the effects of feedstock cost on the cost of oil.**

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* A more recent SRI report shows about 38 mills/kWh for a 50 MWe plant (11).

** A recent SRI report (11) shows a $3.50/MM Btu oil cost (private financing excluding feedstock) for a 5268 BPD catalytic liquefaction of wood plant versus about $6/MM Btu (utility) and $9/MM Btu (private) estimated here.

TABLE 7. ANNUAL INPUTS AND OUTPUTS REQUIREMENT USING CONSISTENT LOAD FACTORS

	Load Factor	Input	Output
Wood-to-Power	255 days/yr, 69.9%	Wood - 477,207 tons, or 4.357 trillion Btu at 9.13 MM Btu/ton	Power (net)- 275.9 MM kWh 0.9416 trillion Btu
Coal-to-Power	255 days/yr, 69.9%	Coal - 1,068,720 tons or 27.857 trillion Btu at 26.066 MM Btu/ton	Power (net)- 2,913 MM kWh 9.942 trillion Btu
Straw/Manure to-Gas	328.5 days/yr, 90.0%	Straw - 328,500 tons or 4.71 trillion Btu at 14.34 MM Btu/ton	Gas - 2.1886 trillion Btu 2,304 MMSCF
		Manure - 328,500 tons or 0.96 trillion Btu at 2.92 MM Btu/ton	
HYGAS	328.5 days/yr, 90.0%	Coal - 6,725,000 tons or 118.36 trillion Btu at 17.60 MM Btu/ton	Gas - 82.125 trillion Btu 89,910 MMSCF
Wood-to-Oil	333.3 days/yr, 91.3%	Wood - 655,000 tons or 6.52 trillion Btu at 9.954 MM Btu/ton	Oil (Fuel Oil) - 588,000 bbl 3.704 trillion Btu (HHV)
H-Coal	333.3 days/yr, 91.3%	Coal - 9,277,740 tons or 220.8 trillion Btu at 23.80 MM Btu/ton	Oil (Naphtha and Fuel Oil) - 22,283,200 bbl 139.186 trillion Btu (LHV)

TABLE 8. ECONOMIC COMPARISON SUMMARY FOR BIOMASS AND COAL CONVERSION PROCESSES (BASED ON $/TON)

BIOMASS CONVERSION

Wood-to-Power (45 MWe)

Wood Cost $/ton	Power Cost, Mills/kWh	
	Utility	Private
0	28.5	45.5
10	45.8	62.8
20	63.1	80.1
30	80.4	97.4
40	97.7	114.7

Straw/Manure-to-Gas (6.66 MMM Btu/day)

Straw $/ton	Manure $/ton	Gas Cost, $/MM Btu	
		Utility	Private
0	0	7.68	10.63
5	1	8.58	11.53
10	2	9.48	12.43
15	3	10.38	13.33
20	4	11.28	14.23
25	5	12.19	15.13

Wood-to-Oil (1,764 BPSD)

Wood Cost $/ton	Fuel Oil Cost, $/bbl	
	Utility	Private
0	39.23	51.99
10	50.37	63.13
20	61.51	74.27
30	72.65	85.41
40	83.79	96.55

COAL CONVERSION

Coal-to-Power (476 MWe)

Coal Cost $/ton	Power Cost, Mills/kWh	
	Utility	Private
0	19.0	32.0
10	22.7	35.6
20	26.4	39.3
30	30.0	43.0
40	33.7	46.6

Coal Gasification-HYGAS (250 MMM Btu/day)

Coal Cost $/ton	Gas Cost, $/MM Btu	
	Utility	Private
0	2.42	3.75
5	2.84	4.17
10	3.25	4.60
15	3.66	5.02
20	4.07	5.44
25	4.48	5.87

Coal Liquefaction-H-Coal (66,856 BPSD)

Coal Cost $/ton	Fuel Oil Cost, $/bbl	
	Utility	Private
0	13.72	20.37
10	17.91	24.57
20	22.10	28.78
30	26.28	32.98
40	30.47	37.18

TABLE 9. ECONOMIC COMPARISON SUMMARY FOR BIOMASS AND COAL CONVERSION PROCESSES (BASED ON $/MM BTU)

BIOMASS CONVERSION

Wood-to-Power (45 MWe)

Wood Cost $/MM Btu	Power Cost, Mills/kWh	
	Utility	Private
0	28.5	45.5
1	44.3	61.3
2	60.1	77.2
3	76.0	93.0
4	91.8	108.8

Straw/Manure-to-Gas (6.66 MMM Btu/day)

Straw $/MM Btu	Manure $/MM Btu	Gas Cost, $/MM Btu	
		Utility	Private
0	0	7.68	10.63
0.5	0.5	8.98	11.93
1.0	1.0	10.27	13.22
1.5	1.5	11.57	14.52
2.0	2.0	12.86	15.81
2.5	2.5	14.16	17.11

Wood-to-Oil (1,764 BPSD)

Wood Cost $/MM Btu	Fuel Oil Cost, $/bbl	
	Utility	Private
0	39.23	51.99
1	50.32	63.08
2	61.41	74.17
3	72.49	85.26
4	83.58	96.35

COAL CONVERSION

Coal-to-Power (476 MWe)

Coal Cost $/MM Btu	Power Cost, Mills/kWh	
	Utility	Private
0	19.0	32.0
0.5	23.8	36.7
1.0	28.6	41.5
1.5	33.4	46.3
2.0	38.2	51.1

Coal Gasification-HYGAS (250 MMM Btu/day)

Coal Cost $/MM Btu	Gas Cost, $/MM Btu	
	Utility	Private
0	2.42	3.75
0.25	2.79	4.12
0.50	3.15	4.49
0.75	3.51	4.87
1.00	3.87	5.24
1.25	4.24	5.61

Coal Liquefaction-H-Coal (66,856 BPSD)

Coal Cost $/MM Btu	Fuel Oil Cost, $/bbl	
	Utility	Private
0	13.72	20.37
0.5	18.70	25.37
1.0	23.69	30.37
1.5	28.67	35.37
2.0	33.65	40.37

The two to three times higher cost factor could be reduced by a combination of: (1) improvement in wood conversion efficiency, (2) increase in plant size, and (3) a relative price advantage of wood versus coal.

On the basis of these economic estimates, the three biomass conversion plants do not produce clean energy products at costs competitive with current prices of the same or similar products; neither do the coal gasification and liquefaction plants. The product costs do not appear to be competitive with those for large-scale coal conversion facilities, except perhaps for wood-to-power. It is likely that the product cost differentials could be reduced by process improvements and more favorable comparison assumptions. For example, product distribution costs were excluded in all cases. Distribution costs for biomass-derived energy products used locally could be considerably lower than the costs for distribution of coal-derived products from large conversion plants.

ENVIRONMENTAL COMPARISONS

As in the economic comparison, the effect of the disparate plant sizes makes an environmental comparison difficult. The biomass conversion plants have an economic disadvantage (small capacity) and an environmental advantage (small capacity) which must be kept in mind.

Sections 3, 4, and 5 present brief descriptions of the regional settings and hypothetical sites for both biomass and coal scenarios. These sections summarize the environmental impacts which would be expected to occur at the hypothetical sites should biomass or coal scenarios be implemented. Similar summaries of impacts were also presented for feedstock procurement scenarios.

In this report, pairs of biomass and coal facilities are compared with respect to the types and magnitudes of impacts anticipated. Where possible, impacts are described on a per unit basis (e.g., acres per kWh, mg/l per Btu, etc.) to permit a more direct comparison of facilities which are widely different in size or production capacity. However, many impacts either cannot be quantified (e.g., aesthetics) or may not be linearly proportional to the facility size (e.g., acres of land committed); these potential problem areas in comparison are identified as they arise in the discussions.

Biomass and coal facilities (and feedstock procurement) have been paired according to the product of the process, with site characteristics kept about the same within the pair. Since site factors can influence impacts and impact magnitude, different processes cannot be directly compared in this study. Also, impacts from actual implementation of a coal or biomass plant may vary since site characteristics will probably differ from the hypothetical descriptions given in this report. Factors such as aesthetic resources, i.e., the visual worth or scenic value of a location, are highly site-specific. Therefore, the range and general nature of impacts expected are indicative only of differences between similar processes which may be used to determine environmentally preferable alternatives, potential areas for continued study, and areas where mitigation may be profitably applied.

Construction of a conversion plant, like that of any industrial facility, involves site preparation, building construction, transportation access, and utility hookups. These activities affect land use on the plant site; the site becomes committed for use by the plant for the operating life of that plant and, in the case of refuse disposal or mine reclamation, may be permanently altered. These land use changes and other effects, such as water pollution from site erosion or waste discharge, air pollution from fugitive dust and equipment emissions, traffic congestion, an influx of people and money into the region, and a demand on community services, are generic to all scenarios, regardless of feedstock, product, or location. However, the significance of these impacts does vary with type of feedstock used (wood, straw/manure, or coal), the product (electricity, synthetic pipeline gas, or synthetic fuel oil), the location (south central, midwest, eastern, or northeastern U.S.), and the size of the facility.

Conversion plant operational impacts vary with the process as well as with the feedstock, with air, water, and solid waste emissions the primary direct causes of environmental impact. While the location and size of the plant are important, the actual chemical composition of the wastes may be an overriding consideration in determining the significance of the impacts.

Feedstock procurement affects the environment by the removal of a material. The significance of the impact depends on the area affected and the amount of physical disturbance of that area.

A numerical rating system with nonweighted factors (Table 10) is used here to compare general feedstock procurement and plant impacts for each biomass-coal pair. Relative (to plant output) rather than absolute impacts are compared to avoid the obvious conclusion that small biomass plants will have less impact than large coal plants.

Scenario 1

Conversion of forest residues or coal to electricity will result in roughly the same rates of consumption of natural resources (Table 11), although the wood conversion plant requires more feedstock because of the lower Btu value of the fuel and the lower conversion efficiency. Feedstock procurement for the coal-fired plant will have significantly more potential for impact due to the need to remove topsoil and overburden to get at the coal (Tables 10, 12). Impacts on air, water, soils, ecology, and aesthetics are particularly important to this analysis. Strip mining will result in physical changes that have both short-term and long-term impacts. Even though much more land area is affected by residue collection, actual physical changes to the harvested areas will be much less pronounced than if mining were to occur. Prompt reclamation of strip-mined areas can help mitigate the impacts of physical distrubance.

While the coal-fired power plant is larger and therefore will contribute more energy to the power grid, the overall environmental impact per MWe will be similar in type and extent for both wood and coal (Tables 10, 12). Air and water emissions will be roughly similar in type and relative quantity, although considerably more sulfur dioxide per kWh output will be released by the coal-fired plant even with 90 percent sulfur dioxide (SO_2) removal. The coal-fired plant also will produce much more solid waste (more ash in coal and the SO_2 scrubber sludge). The chemical makeup of coal ash and the potential leachate

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TABLE 10. SAMPLE NUMERICAL RATINGS FOR QUALITATIVE ASSESSMENTS

Scale	Environmental Qualitative Assessment
+10	Significant benefit
9	
8	
7	
6	
5	Moderate benefit
4	
3	
2	
+1	Insignificant benefit
0	No discernible impact
-1	Insignificant adverse short-term impact
2	
3	Moderate adverse short-term impact
4	
5	Significant adverse short-term impact
6	Insignificant adverse long-term impact
7	
8	Moderate adverse long-term impact
9	
-10	Significant adverse long-term impact

TABLE 11. COMPARISON OF PRINCIPAL RESOURCE REQUIREMENTS — WOOD AND COAL TO POWER

Resource Category Normalized Units	Wood-to-Power 45 MWe (net)	Coal-to-Power 476 MWe (net)
Land, acres/MWe	1.1	0.77
Feedstock, lb/kWh (Btu/kWh)	3.46 (15,790)	0.734 (9,563)
Auxiliary Fuel, Btu/kWh	188	169
Power (Consumed), kW/kW	0.109	0.06
Chemicals, lb/kWh	0.00046	0.022
Water, gal/kWh	0.82	0.51
Manpower, men/MWe	0.67	0.2

from disposal can prevent significant adverse impacts. Overall, the wood-fired plant may be environmentally preferable in this scenario because of the potentially lower impact of feedstock procurement.

Scenario 2

The HYGAS process for conversion of coal to synthetic gas will consume fewer natural resources per Btu of product than the straw/manure to SPG process (Table 13), partly because of the higher Btu feedstock and higher conversion efficiency and partly because of the economy of scale in the plant. As in Scenario 1, feedstock procurement for HYGAS, which will involve surface mining, will have potentially more adverse impact on air, water, soils, ecology, aesthetics, and land use (Tables 10, 14), although straw procurement will require a larger commitment of acreage. Care must be exercised in the collection of the wheat straw to avoid significant damage to soils, but otherwise there would not be the actual physical disturbance to land that would occur in mining.

Plant air emissions of fugitive dust and hydrocarbons would be relatively lower for the biogas plant, but nitrogen oxides emissions could be higher. Both plants could have potential solid waste disposal problems. The biogas plant will have much more residue to dispose of, but the potential for use as a soil conditioner or cattle feed may offset the disadvantage of its large quantity relative to HYGAS ash. The potential for hazardous materials in some air emissions and solid wastes from the HYGAS process is of concern, but the overall extent of the plant's regional impact will be similar to that of the biomass

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TABLE 12. RELATIVE ENVIRONMENTAL IMPACT SUMMARY OF WOOD AND COAL TO POWER*

Site Specific Factors	Feedstock Procurement		Conversion Plants	
	Wood Residue	Coal	Wood	Coal
Climatology and Meteorology	0	0	-1	-1
Air Quality	-1	-1	-6	-6
Surface Water Availability	0	-1	-1	-1
Surface Water Quality	-1	-6	-1	-1
Groundwater Availability	0	-7	0	0
Groundwater Quality	0	-7	-6	-6
Soils, Geology	-7	-9	-6	-8
Land Availability	-1	-1	-6	-6
Ecology	1	-7	-6	-6
Aesthetic Resources	1	-8	-7	-8
Historical, Archaeological Resources	0	-7	-6	-6
Community Economy	5	5	5	5
Community Population and Services	0	-6	-1	-2
Labor Availability	1	-1	-1	-1
Power Availability	0	0	5	10
Transportation Availability	-6	-6	-6	-6
TOTAL	-8	-62	-44	-43

*See Table 10 for rating scale.

TABLE 13. COMPARISON OF PRINCIPAL RESOURCE REQUIREMENTS — STRAW/MANURE AND COAL TO SPG

Resource Category, Normalized Units	Straw/Manure-to-SPG 6.66 MMM Btu/day	Coal-to-SPG (HYGAS) 250 MMM Btu/day
Land, acres/MM Btu/hr	0.5	0.07
Feedstock, lb/MM Btu	600.4	163.8
Auxiliary Fuel, Btu/MM Btu	544	134
Power (Consumed), kW/MM Btu/hr	19.6	0
Catalysts and Chemicals, lb/MM Btu	5.6	0.071
Water, gal/MM Btu	42.9	11.1
Manpower, mh/MM Btu	0.09	0.019

conversion process (Table 14). Excluding the feedstock procurement impacts, neither process would have a clear environmental advantage.

Scenario 3

The rate of consumption of resources per million Btu of product oil will be greater for wood-to-oil conversion than for coal-to-oil (H-Coal) conversion as indicated in Table 15. This again is due to the lower Btu value of the feedstock, the lower conversion efficiency, and the smaller scale of the wood-to-oil plant. The high waste heat load does result in a greater water consumption for H-Coal. Waste disposal for the deep coal mine, and associated impacts on water and topography, result in greater potential for adverse impact for coal procurement than for forest residue collection (see Table 10, 16). The difference in feedstock procurement impact is similar to that described for Scenarios 1 and 2. Physical/chemical emissions from the plants will be roughly similar overall, with individual pluses and minuses for both plants. Wastewater from both plants may be difficult to clean up and potentially could contain hazardous compounds. The H-Coal plant will generate considerably more solid waste residue for disposal. As in the other processes, there is no apparent overall difference in significance of adverse plant operational impacts. However, the potential for the presence of hazardous materials in H-Coal wastes could present a problem for air, water, and biological environments. Careful

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TABLE 14. RELATIVE ENVIRONMENTAL IMPACT SUMMARY OF STRAW/MANURE AND COAL TO SPG*

Site Specific Factors	Feedstock Procurement		Conversion Plants	
	Straw/Manure	Coal	Straw/Manure	Coal
Climatology and Meteorology	0	0	-1	-2
Air Quality	-6	-2	-6	-6
Surface Water Availability	0	-1	-1	-1
Surface Water Quality	-1	-6	-1	-1
Groundwater Availability	0	-7	-6	-6
Groundwater Quality	0	-7	-6	-7
Soils, Geology	-7	-8	-7	-6
Land Availability	0	-1	-6	-6
Ecology	0	-7	-6	-6
Aesthetic Resources	0	-8	-7	-7
Historical, Archaelogical Resources	0	-7	-6	-7
Community Economy	5	5	5	5
Community Population and Services	0	0	-1	-2
Labor Availability	1	1	-1	-2
Power Availability	0	0	5	10
Transportation Availability	-6	-6	-6	-6
TOTAL	-14	-54	-51	-48

*See Table 10 for rating scale.

TABLE 15. COMPARISON OF PRINCIPAL RESOURCE REQUIREMENTS — WOOD AND COAL TO FUEL OIL

Resource Category, Normalized Units	Wood-to-Fuel Oil 1,764 BPD	Coal-to-Fuel Oil (H-Coal) 66,856 BPD
Land, acres/MM Btu/hr	0.24	0.024
Feedstock, lb/MM Btu	353.7	133.3
Auxiliary Fuel, Btu/MM Btu	3,590	79
Power (Consumed), kW/MM Btu/hr	39.5	Net production
Catalysts and Chemicals, lb/MM Btu	1.15	0.545
Water, gal/MM Btu	27.2	31.35
Manpower, mh/MM Btu	0.078	0.011

management of waste disposal can minimize potential environmental problems. Because of the lower feedstock procurement impact, the wood liquefaction facility might be considered a better environmental choice in this scenario.

CONCLUSIONS AND RECOMMENDATIONS

Four of the six conversion processes can be considered as advanced processes not yet in the commercial-plant stage that was assumed in the scenarios. Much developmental work is still needed to provide detailed engineering data for commercial installations. Similarly, more experimental data are needed to adequately characterize environmental emissions from both the biomass and coal conversion processes. Pollution control technologies applicable to the processes need further evaluation to identify best available technologies and their effectiveness and costs. Some of this work is already underway, and no specific recommendations are offered.

It is felt that this type of scenario comparison of hypothetic commercial-scale plants is a useful way of identifying major advantages and disadvantages of biomass versus coal conversion. This approach also illustrates, mainly by data absence, places where important information is needed to make proper comparative evaluations. Publication of up-to-date process and environmental information from pilot and demonstration-scale biomass conversion facilities would help to make these types of evaluations or comparisons more useful. It

TABLE 16. RELATIVE ENVIRONMENTAL IMPACT SUMMARY OF WOOD AND COAL TO SYNTHETIC FUEL OIL*

Site Specific Factors	Feedstock Procurement		Conversion Plants	
	Wood Residue	Coal	Wood	Coal
Climatology and Meteorology	0	0	-1	-1
Air Quality	-1	-1	-6	-9
Surface Water Availability	0	0	0	0
Surface Water Quality	-1	-7	-1	-1
Groundwater Availability	0	-7	0	0
Groundwater Quality	0	-6	-6	-6
Soils, Geology	-7	-8	-6	-6
Land Availability	-1	-6	-6	-6
Ecology	1	-9	-6	-6
Aesthetic Resources	1	-3	-10	-9
Historical, Archaeological Resources	0	0	-6	-6
Community Economy	5	5	5	5
Community Population and Services	0	0	-1	-1
Labor Availability	1	0	-1	-1
Power Availability	0	0	5	10
Transportation Availability	-6	-6	-6	-6
TOTAL	-8	-48	-46	-43

*See Table 10 for rating scale

is also recognized that many biomass conversion (and coal conversion) processes are proprietary in nature, and hence certain process and environmental details will remain unavailable to the public. A standard method of cost estimation and economic analysis would also be useful to many organizations so that economic comparison of different biomass conversion processes could be made more easily.

From this scenario study, several conclusions and recommendations can be made for biomass versus coal, using coal conversion as the basis for comparison.

Biomass conversion plants will almost intrinsically be of small commercial scale, given the low area densities and low bulk densities of most biomass materials compared with coal deposits. Thus, biomass conversion plants will almost intrinsically suffer losses of economy-of-scale with respect to the much larger coal conversion facilities. Conversion efficiencies of the three biomass conversion processes were lower on a Btu-in/Btu-out basis than the three respective coal conversion processes. These two factors combine to make the production costs of clean energy from biomass considerably higher than the costs of similar products from coal. Low biomass feedstock costs relative to coal appear to be very important to the economic viability of biomass conversion.

Environmental impacts of the three biomass conversion plants themselves (i.e., without including resource collection) will be smaller in an absolute sense because the plants are smaller. On a relative basis, the impacts may be of different types in some cases, but the overall plant impacts are similar (the processing plants do basically the same thing, but the scale is different). If the coal conversion plants were on the same small scale, the biomass conversion plants would be environmentally preferable. Pollution control investments for large coal conversion facilities will be extensive, but these control costs, though substantial, will not shift the economics enough to favor small-scale biomass conversion plants with their lower conversion efficiencies. That is, the cost of reducing pollutant emissions to environmentally acceptable levels does not dominate the economics of coal conversion.

Collection of biomass residues from farmland and forestland should have fewer adverse environmental consequences than coal mining. Management programs would be needed to avoid overharvesting of residues. Experimental test collection programs should be carried out to determine optimum harvesting schemes and costs. There is also the environmental benefit of utilizing a renewable resource rather than a nonrenewable material such as coal. Low-cost methods of improving the heating values (removing moisture) and increasing the bulk densities of biomass materials are needed to offset these disadvantages with respect to coal, at least in thermal biomass conversion processes.

Of the three biomass conversion processes, wood-fired power plants appear to offer the best possibility for near-term implementation. There are, of course, many wood-fired steam and power boilers operating today in the pulp and paper industry. In wood-rich areas where the cost of purchased electricity or the cost of fossil fuels is high, wood-fired plants should be logical candidates for economic evaluation. Co-firing of wood and fossil fuels in steam-electric generating units may become more widespread if retrofit costs can be overcome by a lower wood fuel cost. Larger, more efficient wood-fired generating stations are a possibility in the future if delivered wood fuel costs can be kept low.

Anaerobic digestion of biomass is unlikely to become a major route to high-Btu gas. A better understanding of the biological conversion mechanisms is an important research need. The practical goal is a significant improvement in conversion efficiency. For the present, however, evaluations of anaerobic digestion should focus on a more favorable application such as:

- Small-scale plants producing medium-Btu gas (no upgrading) for local consumption (e.g., industrial fuel or gas-turbine power generation)
- Low cost, intrinsically wet feedstock produced year-round in high local concentration (e.g., cattle manure from a large feedlot or manure plus microalgae produced from feedlot waste)
- Evaluation of unconverted residue as animal feed or soil amendment (i.e., a salable byproduct is needed)

Wood liquefaction is also unlikely to become a major route to fuel oil. Further experimental work on conversion processes (both pyrolysis and catalytic reduction) may lead to significant improvements in yields and oil properties, but there is a very substantial economic disadvantage to overcome.

Investigation of other scenarios should be more attractive for biomass conversion: for example, chemical synthesis from cellulose materials and production of ethanol by hydrolysis/fermentation processes. A combination of three factors is desirable:

- A relatively low-priced biomass feed material
- A process that has a relatively high conversion (actual or potential)
- A higher-priced product than oil or gas

If the economics improve, then the relative environmental benefits of biomass conversion versus coal conversion will become a more persuasive force toward renewable resource utilization. At this point, however, coal conversion into clean fuels such as gas and oil seems much more promising because of the clearly superior economics.

SECTION 3

SCENARIO 1-
WOOD AND COAL TO POWER IN THE SOUTH CENTRAL REGION

In this scenario, a 50 megawatt (MWe) wood-fired power plant and a 500 MWe coal-fired plant are to be constructed and operated in the south central region of the U.S. Figure 5 indicates the regional location. Each plant will be located at a similar, hypothetical site. Offsite power transmission facilities are excluded from the scope.

A regional environmental setting is presented as well as brief site descriptions. The settings provide a background for assessing the general impacts of feedstock procurement and of plant operation. Environmental assumptions include the applicability of proposed (draft) new source performance standards (NSPS) for electrical utility steam generating units of more than 250 MM Btu/hr input capacity (see Table 2). There are no unusually stringent state or local or environmental regulations that are assumed to be applicable. Preconstruction environmental costs are excluded from consideration, however.

REGIONAL ENVIRONMENTAL SETTING

The biomass and coal energy conversion plants are located at a hypothetical location in the Southern Coastal Plains of the U.S. in a state such as Georgia, Alabama, or Tennessee. The following sections describe this region's environmental setting.

Land Use

Except for small urban use, almost all the land area in the region is in farms. Federal land ownership is quite limited. One-half to three-fourths of the area is woodland, most in small holdings, but some in large tracts. The proportion of woodland is greatest in the western portion of the region. Cropland area varies between one-third of total in the east to about one-tenth in the west. Less than one-tenth of the area is in pasture. A recent trend is to more pasture and woodland and less cropland (13).

The Southern Coastal Plains region is the heart of the old Cotton Belt. Cotton has long dominated regional agriculture as a cash crop. General farming based on cotton, corn, and forage crops is the rule (14). Tobacco is important in sections of Georgia and the Carolinas, peanuts are important in southwestern Georgia and neighboring parts of Alabama, and potatoes are important in southwestern Alabama.

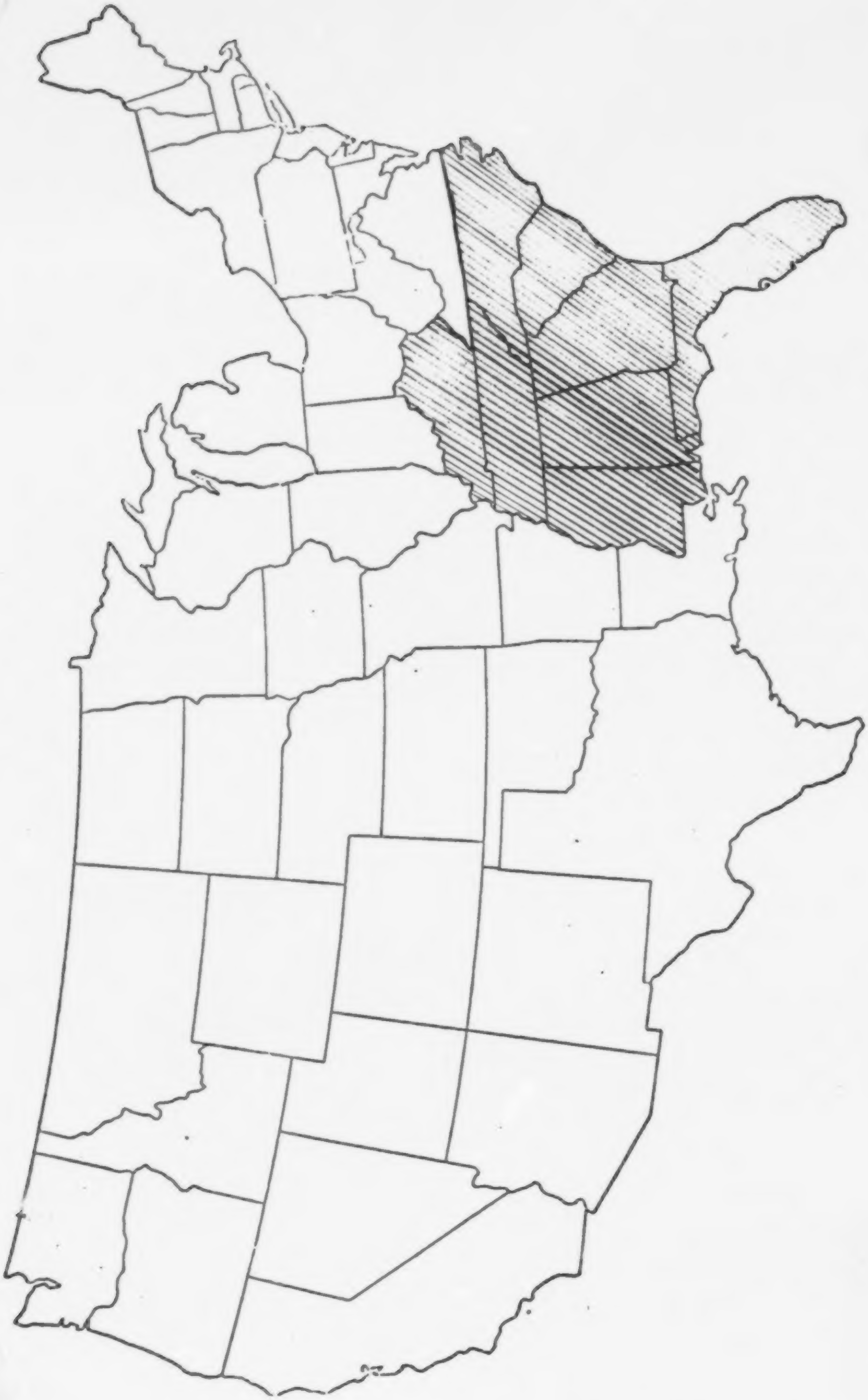

Figure 5. Wood and coal to power region – Scenario 1.

Topography and Elevation

The Southern Coastal Plains form a belt up to 400 miles wide around the Gulf of Mexico.

The topography is diverse. The elevation generally varies between 100 and 600 feet, increasing gradually from the lower Coastal Plain to the Piedmont. Stream valleys are narrow in their upper reaches, but in the lower parts they broaden out and form widely meandering stream channels. Local relief is mainly in a few tens of feet, but some of the more deeply dissected parts exhibit relief of 100 to 200 feet (13).

Climate

Average annual precipitation varies between 40 and 60 inches. Between 50 and 70 percent of the total annual rainfall occurs during the cool season, October to March. The frequent shortage of rainfall in the crop growing season is a perennial problem in the region (13, 14).

The region has a long growing season and mild winters. The number of frost-free days ranges from 200 days per year in the north to 280 days in the extreme south. The average winter temperature is abour 45°F throughout the area. The average annual temperature ranges between 60°F in the north and 68°F in the south.

Soils

Red-yellow Podzolic soils dominate the region. They developed generally from a variety of parent materials under conditions of a high degree of weathering and leaching of bases. The soils are predominantly acid and low in organic matter and in plant nutrients. The soils developed from marine sands and clays, and the predominantly sandy surfaces are naturally erosive. Under high-intensity rains during spring and summer, soil loss is a big problem, especially on hilly terrain. Moreover, the coarse-textured soils do not hold the moisture well. At the other extreme, some areas of clay and sandy clays (low-humic gley and humic gley soils) are found which often do not permit ready infiltration (13, 14, 15).

Vegetation

Two major forest and range ecosystems in the Southern Coastal Plains are the "longleaf-slash pine" and the "loblolly-shortleaf pine" ecosystems (16). The latter is the largest ecosystem in the south and southeast in terms of area.

The longleaf-slash pine ecosystem is confined to flat and irregular southern Gulf Coastal Plains on relief less than 300 feet. About 50 percent or more of the stand is longleaf pine *(Pinus palustris)* or slash pine *(P. elliottii)*. Common associates include other southern pines, oak *(Quercus spp.)*, and sweet gum *(Liquidambar styraciflua)*. On most sites, grasses either dominate the understory or share dominance with shrubby vegetation. Wiregrasses *(Aristida spp.)* are the dominant herbaceous plants east of the Apalachicola River, but in the western section bluestreams *(Andropogon spp.)* provide most of the herbage. More prominent shrubs are gallberry, saw-palmetto, waxmyrtle, and shining sumac.

The loblolly-shortleaf pine ecosystem generally occurs on irregular Gulf Coastal Plains and the Piedmont on gently sloping lands. Local relief is 100 to 600 feet on the Gulf Coastal Plains and 300 to 1000 feet on the Piedmont.

Approximately 50 percent or more of the stand in this ecosystem is loblolly pine *(Pinus taeda)*, shortleaf pine *(P. echinata)*, or other southern yellow pines. Common associates include oak, hickory *(Carya spp.)*, black gum, red maple *(Acer rubrum)*, and winged elm *(Ulmus alata)*. The main grasses are bluestems, panicums, and longleaf uniola. Dogwood *(Cornus florida)*, viburnum, haw *(Crataegus spp.)*, blueberry, American beautyberry, yaupon, and numerous woody vines are common (16, 17).

Wildlife

A wide variety of wildlife is found in the various regional habitats. White-tailed deer are widespread. Rarely, the black bear or the endangered Florida panther may be encountered in the longleaf-slash pine ecosystem. Common small mammals include the raccoon and fox, which are hunted in many areas.

The longleaf-slash pine forest provides habitat for opposums, tree squirrels, rabbits, and numerous species of ground-dwelling rodents. Wild turkey and the bobwhite quail are common. Similarly, numerous resident and migratory nongame birds and various species of migratory waterfowl are found. The red-cockaded woodpecker is an endangered species. The reptiles are well represented. The largest of the reptiles is the endangered American alligator.

In the loblolly-shortleaf pine forest, wild turkey, bobwhite quail, and mourning dove are quite widespread. The pine warbler, cardinal, summer tanager, Carolina wren, ruby-throated hummingbird, blue jay, hooded warbler, eastern towhee, and tufted titmouse are very common in the mature forest.

WOOD-TO-POWER PLANT SITE DESCRIPTION

The biomass energy conversion plant is located in a rural area on purchased farmland approximately one-quarter mile from a navigable river.

Topography and Elevation

The site, about 50 acres, is gently sloping with no major topographical features and averages about 100 feet in elevation. Rolling to steeply sloping hills rise to about 300 feet in elevation away from the river.

Transportation

A state highway passes within one mile of the plant and a major north-south rail line is within 1½ miles. The nearby river is a major waterway for shipping in the state.

Climate and Air Quality

The climate in the site is continental, but is occasionally influenced by ocean breezes. The winters are mild and of short duration. Snow, sleet, and chilly spells are rare. Summers are long and sometimes hot, but generally tempered by ocean breezes. The average frost-free season is 230 days.

The annual rainfall of about 57 inches is generally well distributed, especially in the cropgrowing season. The driest months are September, October, and November. The area is subject to occasional severe windstorms, hailstorms, and tornadoes usually during February to May. Table 17 summarizes principal climatic conditions at the hypothetical site.

Air quality in the site area is generally good; however, it is currently listed as a nonattainment area for photochemical oxidants.

TABLE 17. ASSUMED CLIMATIC CONDITIONS

Elevation:	100 feet
Temperature:	
Annual Average	67°F dry bulb
	61.5°F wet bulb
5-Percent Design	94°F dry bulb
Conditions	79°F wet bulb
Annual Minimum	8°F
Prevailing Wind:	South at 6.6 mph
Precipitation:	
Annual Precipitation	57 inches
Annual Runoff	25 inches
Annual Lake Evaporation	44 inches
1-yr, 24-hr Storm	3.5 inches
10-yr, 24-hr Storm	7.0 inches
Annual Frost-Free Period:	230 days

Land Use

The immediate vicinity of the site area is predominantly rural. Agriculture is the major industry. Corn and cotton are the main crops. Other crops of importance include winter oats, soybeans, hay, peanuts, sorghum, sweet potatoes, fruit, and vegetables. Much of the area is in range and pasture. About 90,000 acres in the county are woodland.

Water Resources

River flow at the plant averages about 22,730 cfs with a minimum annual daily discharge of about 2000 cfs. Water quality is good; both hardness and dissolved solids are low. (See Table 18.) Mean annual temperature is 60°F with a 44°F to 79°F range. All of the plant water requirements are supplied by the river.

Soils

The site area lies within the region of the Red and Yellow Podzolic soils and within the Gulf Coastal Plains physiographic region. Most soils are acidic and have a light-colored surface soil with a much heavier textured subsoil.

Cattle are pastured on bottomlands near the river and woodlands. Most of the area near the site is sloping to rolling in topography and very erosive, suited mostly to forest. Some of the soil is very acid, very heavy and sticky clay, too difficult to till, and is used for forestry.

Vegetation and Wildlife

The site is principally wooded, with southern yellow pine species predominating. Some shrubby vegetation and grasses are also found, especially near the river where timber clearing has occurred in the past. A small portion of this area near the river is used for cropland. Wildlife on the site is typical of that found in the region, small game animals (mammals and rodents) and a variety of resident and migratory bird species. No rare or endangered species is known to inhabit the site.

FOREST RESIDUE PROCUREMENT

Approximately 480,000 tons (wet) per year of wood chips and bark are consumed by the power plant. On the order of 1.7 million tons (dry) per year of logging waste and collected forestry waste are located within 36 mean transport miles of the plant site. Annual consumption is about 15 percent of this reportedly available waste. In this scenario, the conversion plant owner purchases chips delivered to the plant gate. However, feedstock procurement has associated economic and environmental effects on biomass conversion and is briefly described.

Most of the feedstock is purchased by contract from independent pulpwood producers that harvest forestland mainly in private ownership. In addition to supplying roundwood and some chips to mills in the area, the producers also harvest logging residue for sale to the plant.

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TABLE 18. ASSUMED AVERAGE RIVER WATER QUALITY

Component	Value	Component	Value
pH	7.1	Nitrate	0.3 mg/l
Temperature	44-79°F	Nitrite	0.02 mg/l
Turbidity	35 JTU	Ammonia-Nitrogen	0.07 mg/l
Dissolved Oxygen	9 mg/l	Total Organic Nitrogen	0.3 mg/l
Biochemical Oxygen Demand	3.3 mg/l	Phosphorus	0.1 mg/l
Chemical Oxygen Demand	12 mg/l	Arsenic	0.002 mg/l
Total Dissolved Solids	80 mg/l	Chromium-Total	0.015 mg/l
Calcium	15.9 mg/l	Copper	0.003 mg/l
Magnesium	2.5 mg/l	Iron, Total	1.6 mg/l
Sodium	11.5 mg/l	Lead	0.002 mg/l
Sulfate	38.4 mg/l	Manganese	0.013 mg/l
Chloride	4.3 mg/l	Mercury	0.001 mg/l
Bicarbonate	30.5 mg/l	Zinc	0.02 mg/l
Silica (as SiO_2)	2 mg/l	Phenols	0.001 mg/l

Residues (culls, dead trees, stumps, tops, branches) are collected and chipped in the forest by crews whether during conventional harvesting of round wood or separately during a second pass in the forest track. The crews employ chainsaws for cutting and stripping and dozer-tractors (also mechanical stump pullers) for residue movement to the mobile chippers. Manual collection is also practiced. Chipped residue is blown into trucks for transport to concentration yards or directly to the plant if nearby. At the concentration yards, the chips are unloaded, then reloaded onto larger truck-trailers and rail hopper cars for shipment to the conversion plant. These yarding and shipping operations allow scheduling of shipments to the plant on a regular basis over the year.

Assuming a forest residue concentration of 15 to 17.8 tons/acre, a minimum of 27,000 to 32,000 acres of forestland would need to be harvested for residue each year. Wood growth is about 1.3 tons/acre/year. More land area would actually be affected, since it might not be desirable to practice complete removal in many areas.

WOOD-TO-POWER PROCESS DESCRIPTION

Electric power generation from the combustion of wood wastes is fairly common in the pulp and paper industry. Combination fuel firing is more prevalent than wood-only firing. Most of the installed boiler units have steam capacities below 500,000 lb/hr. The increases in fossil fuel costs have sparked a renewed interest by the utility industry in wood-fired power plants. Large capacity generating stations are probably impractical at present for two reasons: lack of operating experience and large wood-only fired boilers, and uncertainty in the availability and cost of large tonnages of wood fuel. This conversion scenario is based on an industrial-scale power boiler in an an area where, theoretically, fuel availability is not a problem.

Summary

The biomass conversion plant produces about 50 MW of electric power from 1870 tpd of chipped forest residue and bark. The power boiler process used is well established on an industrial utility scale. A local utility has been assumed to be the owner and operator of this facility located in the south central region of the United States. Wood chips and bark are purchased by the utility on a contract basis from loggers and mills in the region and delivered at unit prices ($/ton) at the plant gate (freight included). Wood only is burned in the power plant, but natural gas is available for lightoff. Gas is used as a supplemental fuel in the event of a severe depletion of the onsite wood supply or during peak loads. A conventional steam turbine generator converts steam energy into electrical energy. Power from the main transformer is distributed through transmission lines to a local power grid serving the area's residential, commercial, and industrial users. The plant boundaries are indicated by the fenced area in Figure 6.

The process description is divided into feedstock receiving and storage facilities (Figure 7), the combustion process, the steam generator cycle, and the

40

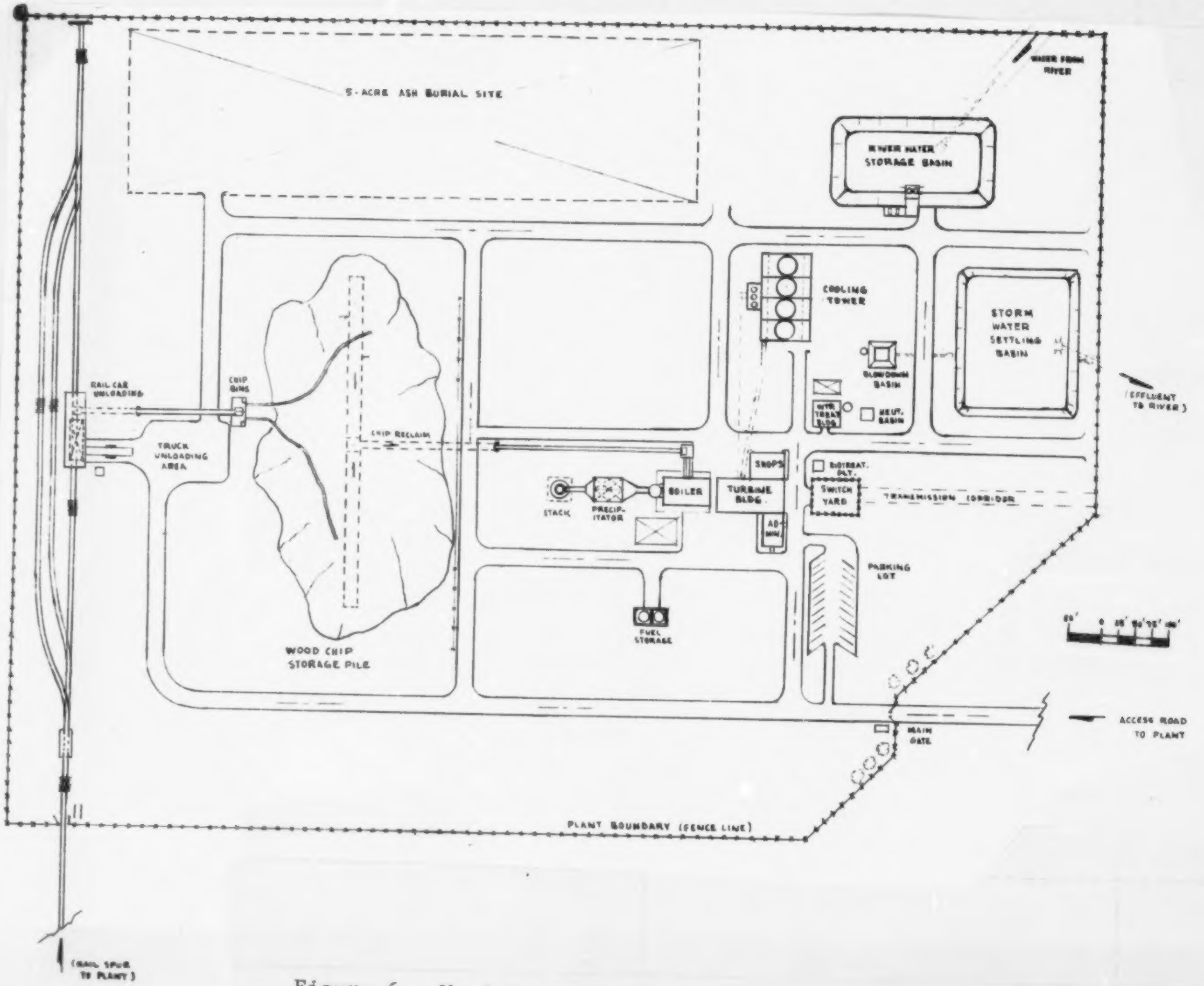
5-ACRE ASH BURIAL SITE
WATER FROM RIVER
RIVER WATER STORAGE BASIN
COOLING TOWER
STORM WATER SETTLING BASIN
BLOWDOWN BASIN
WTR. TREAT. BLDG.
NEUT. BASIN
(EFFLUENT TO RIVER)
RAIL CAR UNLOADING
CHIP BINS
TRUCK UNLOADING AREA
CHIP RECLAIM
WOOD CHIP STORAGE PILE
STACK
PRECIP-ITATOR
BOILER
TURBINE BLDG.
SHOPS
ADMIN
BIOTREAT. PLT.
SWITCH YARD
TRANSMISSION CORRIDOR
PARKING LOT
FUEL STORAGE
50' 0 25' 50' 75' 100'
ACCESS ROAD TO PLANT
MAIN GATE
PLANT BOUNDARY (FENCE LINE)
(RAIL SPUR TO PLANT)

Figure 6. Wood to power plant, general arrangement.

9

41

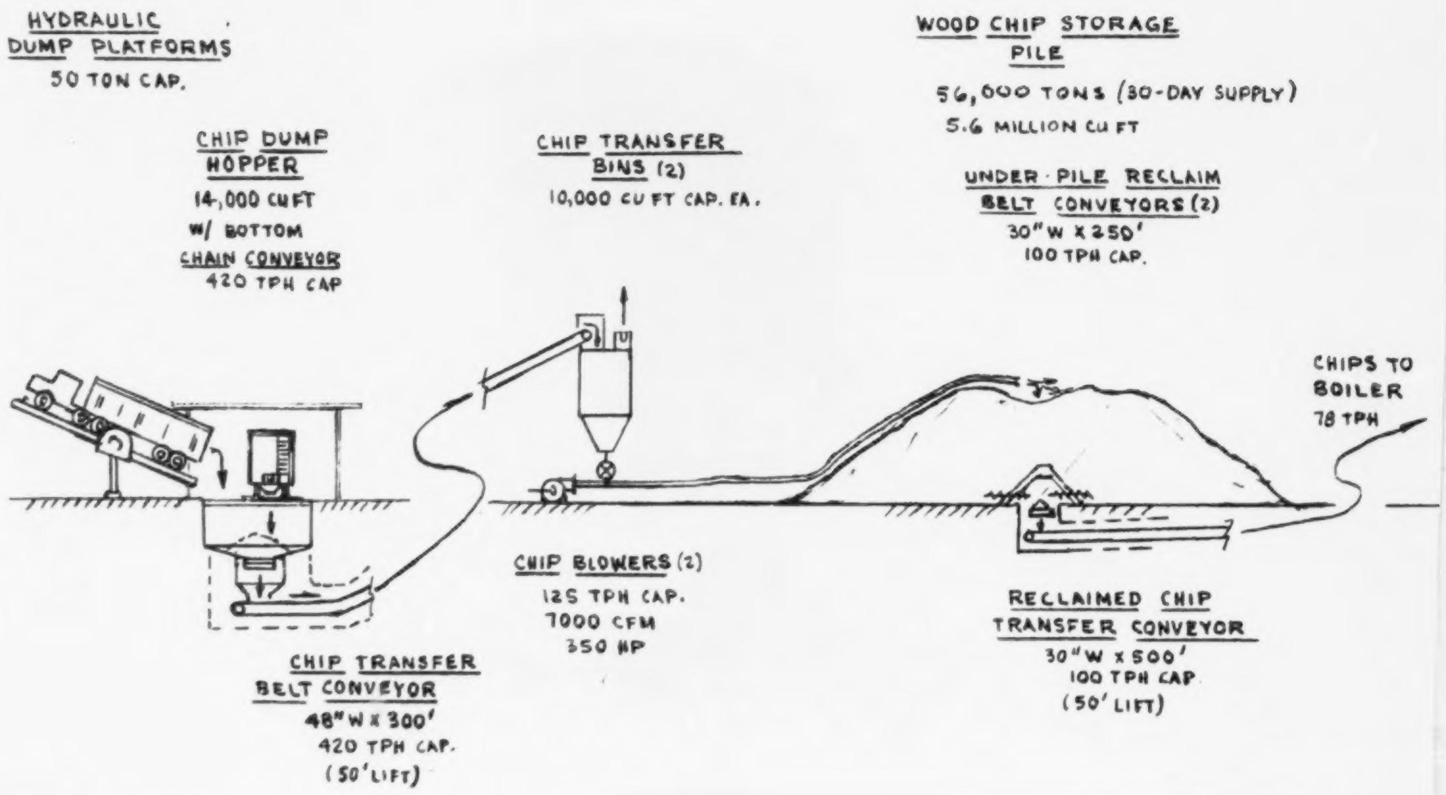
HYDRAULIC DUMP PLATFORMS
50 TON CAP.
CHIP DUMP HOPPER
14,000 CU FT
W/ BOTTOM CHAIN CONVEYOR
420 TPH CAP
CHIP TRANSFER BINS (2)
10,000 CU FT CAP. EA.
WOOD CHIP STORAGE PILE
56,000 TONS (30-DAY SUPPLY)
5.6 MILLION CU FT
UNDER-PILE RECLAIM BELT CONVEYORS (2)
30"W X 250'
100 TPH CAP.
CHIPS TO BOILER
78 TPH
CHIP BLOWERS (2)
125 TPH CAP.
7000 CFM
350 HP
RECLAIMED CHIP TRANSFER CONVEYOR
30"W X 500'
100 TPH CAP
(50' LIFT)
CHIP TRANSFER BELT CONVEYOR
48"W X 300'
420 TPH CAP.
(50' LIFT)

Figure 7. Wood chip receiving and storage section
(wood to power).

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auxiliary facilities (including environmental controls). Design bases and assumptions are summarized below. Figure 8 is a simplified process flow diagram of the conversion process.

Design Basis

A nominal 50 MWe plant capacity was selected as a practical size considering both boiler technology and local fuel resources.

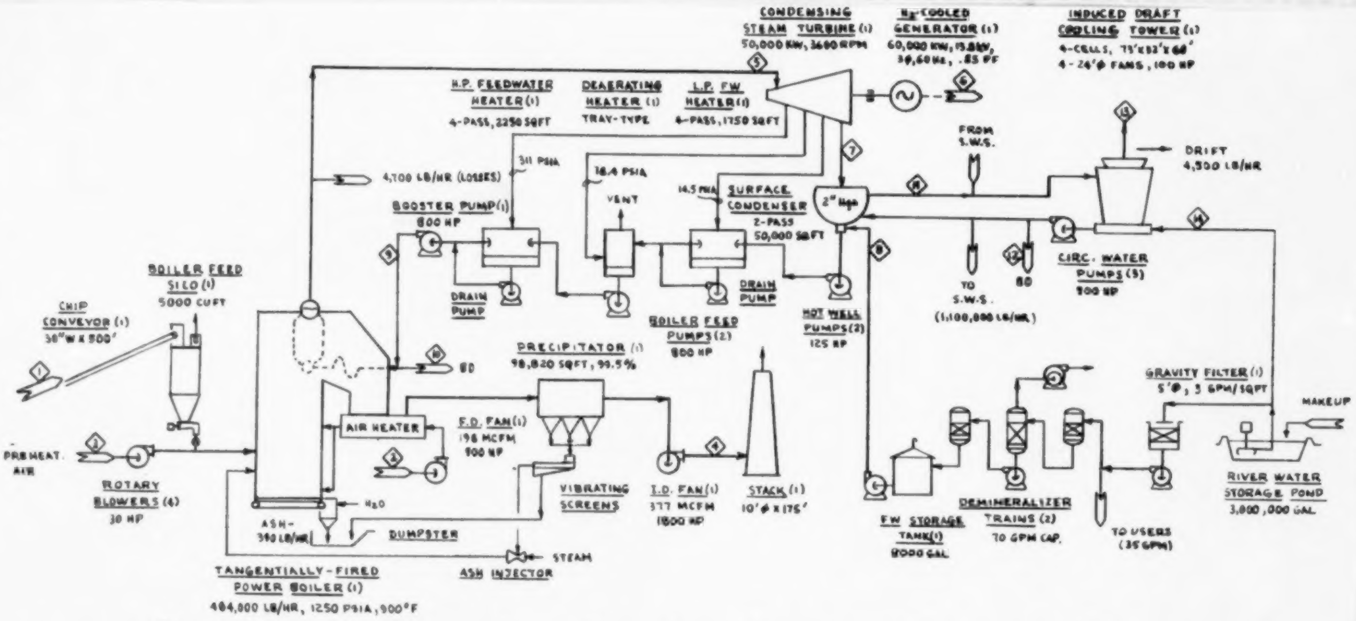
Table 19 indicates the average wood fuel properties assumed. The chipped residue is assumed to be delivered by a mix of rail hopper cars and large trailer trucks.

TABLE 19. ASSUMED WOOD FUEL PROPERTIES

Composition (dry basis)	Value
(Proximate)	
Volatile matter, % wt	79.4
Fixed carbon, % wt	20.1
Ash, % wt	0.5
	100.0
Moisture (as received)	50.0
(Ultimate)	
Hydrogen, % wt	6.3
Carbon, % wt	51.8
Sulfur, % wt	trace
Nitrogen, % wt	0.1
Oxygen, % wt	41.3
Ash, % wt	0.5
	100.0
Heating value (HHV), Btu/lb	9130 (dry) 4565 (as rec'd)
Density, specific, lb/cu ft	60 (green)
Density, bulk, lb/cu ft	20 (chips)

Other principal design bases and assumptions are:

- Onsite fuel storage: 30-day supply
- Boiler: Stoker or suspension-fired furnace, (single pass) drum boiler with superheater, economizer, and air heater


CONDENSING STEAM TURBINE (1)
50,000 KW, 3600 RPM
H2-COOLED GENERATOR (1)
60,000 KW, 13.8KV, 3Φ, 60Hz, .85 PF
INDUCED DRAFT COOLING TOWER (1)
4-CELLS, 73'x32'x60'
4-24'Φ FANS, 100 HP
H.P. FEEDWATER HEATER (1)
4-PASS, 2250 SQFT
DEAERATING HEATER (1)
TRAY-TYPE
L.P. FW HEATER (1)
4-PASS, 1750 SQFT
311 PSIA
18.4 PSIA
14.5 PSIA
4,700 LB/HR (LOSSES)
BOOSTER PUMP (1)
800 HP
VENT
SURFACE CONDENSER
2-PASS
50,000 SQFT
2" Hga
FROM S.W.S.
DRIFT
4,500 LB/HR
DRAIN PUMP
BOILER FEED PUMPS (2)
800 HP
DRAIN PUMP
HOT WELL PUMPS (2)
125 HP
TO S.W.S.
(1,100,000 LB/HR)
BD
CIRC. WATER PUMPS (3)
700 HP
BOILER FEED SILO (1)
5000 CUFT
CHIP CONVEYOR (1)
30"W x 500'
BD
PRECIPITATOR (1)
98,820 SQFT, 99.5%
AIR HEATER
F.D. FAN (1)
198 MCFM
900 HP
PREHEAT AIR
ROTARY BLOWERS (4)
30 HP
H2O
ASH-
390 LB/HR
DUMPSTER
VIBRATING SCREENS
I.D. FAN (1)
377 MCFM
1800 HP
STACK (1)
10'Φ x 175'
STEAM
ASH INJECTOR
TANGENTIALLY-FIRED POWER BOILER (1)
484,000 LB/HR, 1250 PSIA, 900°F
GRAVITY FILTER (1)
5'Φ, 3 GPM/SQFT
MAKEUP
RIVER WATER STORAGE POND
3,000,000 GAL
FW STORAGE TANK (1)
8000 GAL
DEMINERALIZER TRAINS (2)
70 GPM CAP.
TO USERS
(35 GPM)
1
2
3
4
5
6
7
8
9
10
11
12
13
14

DESCRIPTION / COMPONENT	1	2	3	4	5	6	7	8	9	10	11	12	13	14
	WOOD CHIPS FROM PILE	COMBUSTION AIR	FUEL INJECTION AIR	FLUE GAS TO STACK	STEAM AT THROTTLE	GROSS GEN. OUTPUT	TURBINE EXHAUST	BFW MAKEUP	FEED WATER TO BOILER	BOILER BLOWDOWN	HOT WATER RETURN	C. W. BLOWDOWN	C.W. EVAP. LOSS	C. W. MAKEUP
FLOW, M LB/HR	155.95	700.71	35.0	856.30	470.0	-	338.4	14.1	484.1	9.4	21,095	23.0	248.5	276.0
FLOW, M ACFM (GPM)	-	158.87	13.1	240.72	(1319)	-	(681)	(28)	(1135)	(22)	(42,377)	(46)	(497)	(552)
PRESS., PSIA (IN. W.C.)	14.7	(0)	(8)	(1)	1250	-	0.98	45	1440	-	20	55	(0)	35
TEMP., °F	80	80	450	312	900	-	101.	60	411.5	411.5	95	80		60
ENTHALPY, BTU/LB	4565	-	-	-	1438	-	1004	26	387.6	387.6	63	48		28
HEAT RATE, MM BTU/HR	711.914	-	-	-	675.9	170.7	339.8	0.4	187.6	3.6	1329	1.1		7.7
POWER, MW	208.6	-	-	-	198.0	50.01	99.6	0.1	55.0	1.05	389.4	0.3		2.3

Figure 8. Wood to power process flow diagram, combustion and steam cycle.

- Steam Cycle: Single flow (no reheat) 50,000 kW steam turbine, surface condenser, and three feedwater heating stages
- Heat rejection: Mechanical-draft cooling tower
- Flue gas cleanup: 99+ percent particulate removal, wet or dry collection device
- Solid waste disposal: Onsite landfill
- Plant water supply: River water
- Onsite water storage: 3-day capacity
- Plant load factor: 70 percent
- Plant operating life: 30 years

From these general, and perhaps arbitrary, bases, conversion process details were developed. Economic tradeoff studies in many areas would be needed to optimize conversion efficiency versus cost. The conceptual conversion plant is intended to provide a basis for a reasonable assessment of conversion costs and environmental impacts.

Feedstock Receiving and Storage

Wood chips and bark are delivered to the plant by rail hopper car and by end-dump trailer truck, as indicated in Figure 7. The plant is connected to a main rail line by a 1½-mile rail spur and to a state highway by a one-mile all-weather access road. A 14,000-cubic-foot underground hopper dump serves both rail and truck shipments. Rail shipments are handled seven days a week, trucks six days a week during daylight hours. Truck trailers (2000-cubic-foot capacity) are unloaded by a hydraulic dump platform which raises the truck and trailer, allowing the chips to discharge by gravity into the hopper pit. The dump cycle is accomplished in about ten minutes. Bottom-dump hopper cars are unloaded automatically while being pulled slowly over the rail hopper dump. The dump facility is able to handle seven-pocket hopper cars of 7000-cubic-foot capacity.

A multistrand chain conveyor under the hopper transfers the chips onto an enclosed high-speed inclined belt conveyor which carries the chips to a pneumatic transfer system. The chips drop from the conveyor into twin 10,000-cubic-foot bins equipped with dust collectors. Rotary air locks at the bottom feed the chips into the pressurized air stream from the rotary blowers. The chips are pneumatically conveyed through thin-wall pipes to the outside chip storage pile. The pipes lie on the pile surface and are moved periodically to distribute the chips fairly uniformly. Normal feedstock storage is about 56,000 tons (5.6 million cubic feet) or a 30-day fuel supply. The pile covers three to four acres (40-foot average height) and is underlain by the reclaim system. A bulldozer working on the pile pushes chips toward the long axis of the pile.

Two high-speed belt conveyors in an underground tunnel along this axis each feed material to the centroid of the pile. Auger (screw) conveyors mounted on carriages which can move parallel to the belt conveyors, along the axis, draw chips from near the pile bottom, and discharge them onto the moving belts. The auger conveyors are shrouded by a triangular arch of wood and concrete. At the centroid, the chips are transferred onto an inclined-belt conveyor which emerges from the ground beyond the pile and terminates at the hold bin of the boiler pneumatic feeding system. The 100-ton-per-hour reclaim system is able to supply fuel at 125 percent of the boiler design fuel rate.

Combustion System

Wood chips are discharged from the surge bin with a vibrating feeder onto a vibrating distribution conveyor. Chips are distributed equally to four pneumatic feeders. Four blowers inject preheated air into the air-lock feeders to carry the chips into the tangential firing zone of the waterwall furnace. Preheated air is injected through tangential wind boxes high up in the furnace section to promote rapid drying of the wood chips as they enter the combustion zone. Secondary air is injected above the grate to promote complete combustion of the chips in suspension. The traveling grate discharges bottom ash into the ash pit. Design firing rate is about 78 tons per hour.

A forced-draft fan takes outside air and pushes it through the Ljungstrom regenerative air heater, where heat exchange with hot flue gas increases the air temperature to about 450°F. About five percent of the combustion air is used in the pneumatic feed system. The furnace is fired at 40 percent excess air. The heat release rate is about 25 million Btu per cubic foot of furnace volume.

The combustion products (flue gas) pass up into the radiant section of the boiler, where heat is transferred by radiation and convection to the boiler and superheater tubes and to the finned tubes of the economizer. The flue gas is further cooled to about 300°F in the regenerative air heater (AH). A mechanical dust collector is included ahead of the air heater to prevent AH pluggage and to reduce carbon carryover to the precipitator. At the heater exit, the flue gas is about nine inches (W.C.) below the atmospheric pressure.

Flyash is removed from the flue gas in a plate-type electrostatic precipitator at a design collection efficiency of 99.5 percent. Plate collection area is nearly 100,000 square feet. Plate rappers periodically knock collected dust from the plates into hoppers. An ash reinjection system separates (by vibrating screens) grit from the lighter wood ash and educts the ash into the furnace with steam ejectors. Soot blowers periodically remove accumulated deposits from heat transfer surfaces in the boiler. An induced-draft fan boosts the flue gas pressure to just above atmospheric. Flue gas passes into a 10-foot-diameter (at tip) by 175-foot-tall concrete chimney from whence it discharges to the atmosphere. Airside equipment capacity is rated for 120 percent of design flow (144 percent design pressure drop).

The boiler efficiency is about 70 percent. Fuel moisture, the water in the fuel and that produced by combustion of hydrogen, accounts for more than two-thirds of the heat loss.

Steam Cycle

The boiler design steam conditions (continuous) are 474,700 lb/hr, 1250 psia, 900°F at the superheater outlet. The two-drum vertical boiler configuration takes heated feedwater at 411°F and converts it to steam at the above conditions to drive the 50,000 kW condensing turbine. Boiler capacity is 110 percent of the design steam flow. The single-case, single-flow turbine has three extraction points for feedwater heating. About 28 percent of the throttle steam flow is withdrawn from the turbine for three stages of feedwater heating. The turbine exhausts steam at two inches of mercury absolute pressure. Gross turbine output (mechanical energy) is about 52 megawatts. Generator electrical output is about 50 megawatts. Losses from the 60,000 kW hydrogen-cooled generator are about 2½ percent. Electrical power is transformed up to transmission voltage (115 kV) by the main transformer. Overhead transmission lines carry the power to the local utility grid.

Turbine exhaust steam is condensed in a two-pass surface condenser. Temperature rise across the condenser is 15°F (80°F to 95°F). Heat is rejected to the circulating water (tube side) by steam condensing at 101°F on the outside of the tubes (shell side). Boiler feedwater makeup is added to the hot well. The hot-well pump pumps condensate through the first closed feedwater heater. Steam from the turbine condenses in the heater shell, heating the feedwater in the exchanger tubes. The feedwater is deaerated in a contact (tray type) deaerating heater. The third stage is a closed heater. The feedwater temperature increase across each heater is approximately equal (or 100°F). The boiler feedwater pump after the second heater and the booster pump after the third heater boost the feedwater supply pressure to the boiler to about 1360 psig. Steam condensates from the closed heaters are pumped forward to commingle with the feedwater steam. Boiler blowdown and steam losses amount to about three percent (13,800 lb/hr) of the steam circulation.

Auxiliaries

Water Systems--

Figure 9 presents a simplified water balance diagram for the plant. The river water intake structure houses three 55-percent capacity pumps which pump 617 gpm of water through an underground pipeline to the water storage pond. This clay-lined basin of 3,000,000-gallon capacity provides a three-day supply of plant water at the maximum demand of 700 gpm. Basin pumps supply 552 gpm of makeup water directly to the cooling tower basin and 65 gpm of other plant water to a gravity sand filter. Firewater pumps at the basin supply the firewater piping system. The pump motors are connected to the emergency diesel generator.

Plant water is filtered and chlorinated before entering the distribution system. Normal usage is 5 gpm of potable water, 30 gpm of utility water, and 28 gpm of boiler feedwater. The boiler feedwater makeup is demineralized by ion exchange. This system consists of two parallel cation exchange beds followed by a vacuum deaerator and then by two parallel anion exchange beds and a demineralized water storage tank. Fifty-percent sodium hydroxide and 66° Baumé (Be) sulfuric acid are used as regenerants.

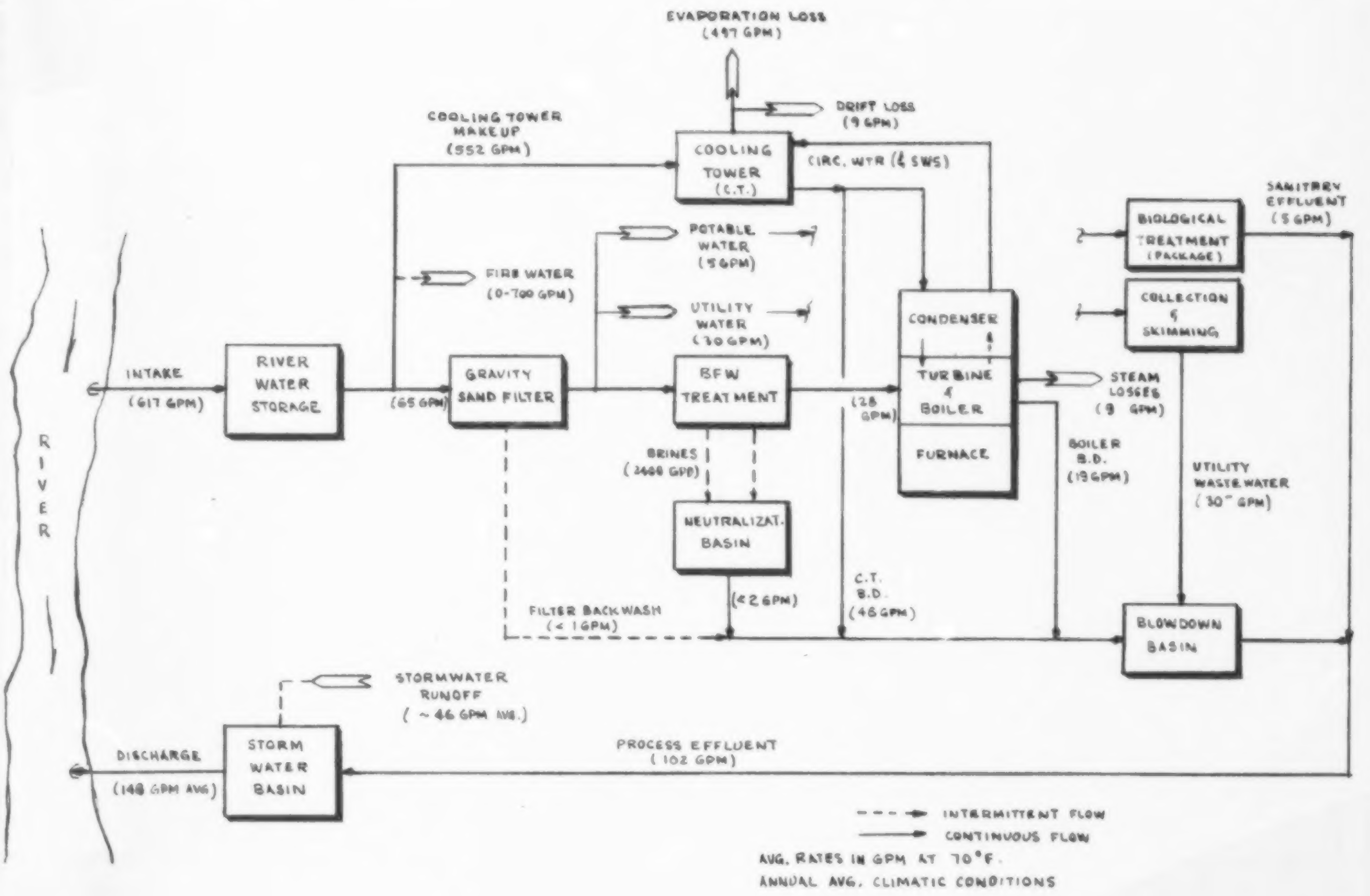

EVAPORATION LOSS (497 GPM)
DRIFT LOSS (9 GPM)
COOLING TOWER MAKEUP (552 GPM)
COOLING TOWER (C.T.)
CIRC. WTR (& SWS)
POTABLE WATER (5 GPM)
FIRE WATER (0-700 GPM)
UTILITY WATER (30 GPM)
BIOLOGICAL TREATMENT (PACKAGE)
SANITARY EFFLUENT (5 GPM)
COLLECTION & SKIMMING
CONDENSER
TURBINE & BOILER
FURNACE
STEAM LOSSES (9 GPM)
RIVER
INTAKE (617 GPM)
RIVER WATER STORAGE
(65 GPM)
GRAVITY SAND FILTER
BFW TREATMENT
(28 GPM)
BRINES (2400 GPD)
NEUTRALIZAT. BASIN
BOILER B.D. (19 GPM)
UTILITY WASTE WATER (30 GPM)
C.T. B.D. (46 GPM)
(<2 GPM)
FILTER BACKWASH (< 1 GPM)
BLOWDOWN BASIN
STORMWATER RUNOFF (~46 GPM AVG.)
STORM WATER BASIN
DISCHARGE (148 GPM AVG)
PROCESS EFFLUENT (102 GPM)
INTERMITTENT FLOW
CONTINUOUS FLOW
AVG. RATES IN GPM AT 70°F.
ANNUAL AVG. CLIMATIC CONDITIONS

Figure 9. Wood to power plant, simplified water balance.

The recirculating cooling water system dissipates the condenser heat load to the atmosphere by evaporation and convection in an induced-draft cooling tower. The tower consists of four cells 73 feet wide by 32 feet long, each equipped with a 24-foot diameter fan (normally three cells are in operation). Hot water (about 42,400 gpm) from the condenser enters the top of the tower and is distributed across the tower fill. The water droplets are cooled as they fall by contact with the induced air and by evaporation of part of the water. Three 55-percent capacity circulating pumps take cooled water from the tower basin and circulate it to the condenser. Blowdown is taken from the discharge side of the circulating pumps. The cooling tower also serves to dissipate heat from the service cooling water system. A service water flow of 2200 gpm is supplied by a 110-percent capacity pump (plus spare) to the bearing coolers, the generator stator and hydrogen coolers, and the turbine oil cooler. The circulating water system is maintained at a minimum of ten cycles of concentration. At annual average conditions (18.5°F approach, 15°F cooling range), evaporation and drift losses are about 497 gpm and 9 gpm, respectively. Total heat dissipation is about 333 MM Btu/hr (97.6 MWt). The circulating water is shock chlorinated for a total of two hours daily.

Wastewater Systems--
Wastewater sources are sanitary sewage, boiler blowdown, cooling tower blowdown, demineralizer brines, yard and floor drains (utility water), and stormwater runoff.

Sanitary wastewater is treated in a package biological system which provides tertiary filtration and disinfection (chlorination). Boiler (19 gpm) and cooling tower (46 gpm) blowdown are collected in a 100,000-gallon lined settling basin which provides 24-hour equalization and settling capacity and dissipation of residual chlorine. Acid and caustic demineralizer brines are discharged to a neutralization basin where caustic is used to neutralize excess acidity and settle out suspended solids before discharge to the blowdown settling basin. Confined yard and floor drainage water are collected in local sumps equipped with oil skimmers. Skimmed water drains to the storm sewers.

Storm drainage is collected from 30 acres of the plant site by a combination surface and underground drainage system. Annual runoff (30 inches) averages 46 gpm of continuous flow. The stormwater retention basin is designed to impound about 60 percent of the total runoff from a ten-year, 24-hour duration storm -- providing about a 14-hour average settling time.

The combined plant wastewater is discharged through a 24-inch diameter gravity pipeline below the river water surface level at approximately mid-channel. The discharge line is about 1000 feet downstream from the intake pumphouse.

Ash Disposal--
Approximately 390 lb/hr of ash is discharged into the furnace ash pit and collected in dumpster boxes. This material, mainly wood ash and grit, is buried in an onsite landfill along with a small amount of plant trash and garbage. The five-acre landfill site is sufficient for solid waste disposal over the 30-year plant operating life (about 3.9 million cubic feet). Conventional spread, compact, and cover techniques are employed. Average fill depth is

20 feet. The site is developed in five-year capacity increments. Soil cover is provided by the excess excavated material stockpiled from plant construction activities.

Other Facilities--
Other auxiliary facilities include plant buildings — turbine hall, warehouse, shops, and administration building — switchyard, parking area, transmission line, access roads, rail spur, fences, gate houses, and other site improvements. Environmental controls are discussed in the plant impact section.

Thermal Balance

The overall plant heat rate is 15,790 Btu/kWh at design (100 percent) conditions. Table 20 summarizes major factors in the plant thermal balance.

The plant's gross electrical output of 50 MWe is about one-quarter of the gross heat input as fuel. A large fraction of the energy loss is heat, dissipated to the atmosphere by flue gases vented from the stack and cooling tower exhaust -- carrying away waste heat picked up by the cooling water in the surface condenser.

TABLE 20. WOOD TO POWER THERMAL BALANCE ELEMENTS

Element	MM Btu/hr	kW	% of Input
Wood Fuel Input	711.9	280,580	100.0
(-) Furnace losses at 30% (rejected to atm)	(123.6)	(62,580)	(30.0)
= Input to steam	498.3	146,000	70.0
(-) Steam cycle losses (mechanical & other heat rejection to atm, water)	(323.2)	(94,700)	(45.4)
= Output at turbine exhaust	175.1	51,300	24.6
(-) Turbine generator losses at 2½% (mechanical & electrical)	(4.4)	(1,290)	(0.6)
= Gross plant output	170.7	50,010	24.0
(-) Auxiliary power losses (turbine auxiliary, transformers, "Hotel" load & electric motor drives)	(16.8)	(4,930)	(2.4)
= Net Plant Output	153.9	45,080	21.6

WOOD-TO-POWER CAPITAL AND OPERATING COSTS

A conceptual estimate was made for the wood-to-power plant located on the hypothetical 50-acre site in the South Central Region of the U.S. Cost estimating methodology for the biomass conversion processes is summarized in Appendix C. The estimate is at first quarter, 1978, price and wage levels, with no allowance for future escalation. Table 21 summarizes the major capital cost elements. Direct field costs are broken down into six categories, themselves composed of summations of materials and labor costs, in most cases. Process mechanical equipment is, of course, the largest direct field cost item. Installed pollution control equipment is about four percent of the direct field cost. The largest cost item is the electrostatic precipitator. Table A-1 in the Appendix identifies major pollution control equipment. This rather low percentage primarily reflects the nature of wood as a clean solid fuel.

Total capital cost for the 45 MWe net plant is about $1200/kWe, perhaps 50 to 60 percent higher than a large coal-fired power plant with fluegas desulfurization, but still significantly more expensive than a plant without an FGD system. As noted in Section 1, we have not attempted to be optimistic in either the conceptual design or the conceptual estimate. For reference, a recent SRI report (11) indicates about $58 million for a 50 MWe (net) wood-fired plant and the city of Burlington, Vermont, estimates $75 million for a 50 MWe plant (19). Mechanical equipment for the feedstock handling and steam generation will be somewhat larger because of wood's low bulk density and low heat content relative to coal.

Annual operating costs are summarized in Table 22 and exclude, for the moment, feedstock costs. Local taxes and insurance comprise the largest single item estimated at two percent of the total plant cost. The $2.2 million operating cost represents about eight mills/kWh (net output) or somewhat higher than coal-fired plant operating costs (about three to five mills/kWh).

Annual costs (simplified) for capital, operation, and feedstock are displayed in Table 23, which represents a 100-percent debt financing at nine percent annual interest. On this simplified basis, the annual wood cost at $10 a net ton is about the same as the annualized capital cost. Figure 10 illustrates the impact of fuel cost on the cost of generating electricity for both private and utility financing. At zero wood cost (unreasonable), the 28 mills/kWh cost of electricity would be competitive with current electricity generating costs (including fuel costs). Fifteen dollars a ton (wet) for wood approximately doubles the cost of electricity. The cost of electricity is indeed very sensitive to wood costs in this estimate. Recent SRI estimates for a 50 MWe plant show the same general results, although their estimate of annual operating costs was about 18 mills/kWh versus about eight mills/kWh in this estimate (11). Private financing of such a facility gives a much higher cost, so that an industrial consumer would be unlikely to finance such a new facility unless the fuel were extremely inexpensive.

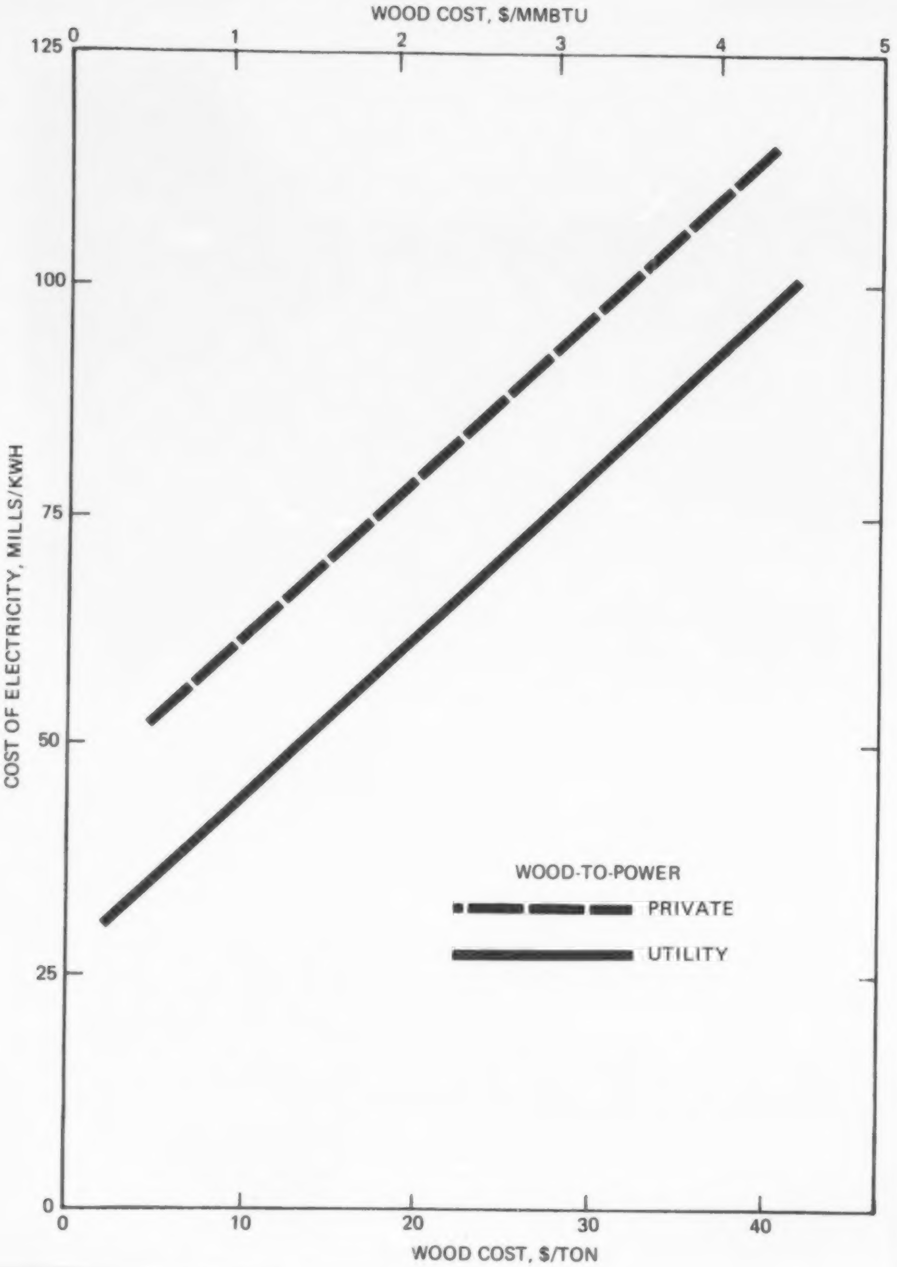


Figure 10. Effect of wood cost on cost of electricity with both private and utility financing.

TABLE 21. WOOD TO POWER CAPITAL COSTS

Element	$1,000,000's
Site and Yard	1.0
Civil/Structural	4.4
Process Mechanical Equipment	15.6
Pollution Control Equipment	1.0
Piping and Instrumentation	3.3
Electrical	1.5
DIRECT FIELD COST	26.8
Indirect Field Cost	4.5
TOTAL FIELD COST	31.3
Engineering Services	3.8
	35.1
Allowance for Uncertainty	7.0
TOTAL CONSTRUCTION COST	42.1
Land	0.2
Other Owner Costs	0.8
Startup	4.2
Allowance for Funds During Construction	4.3
FIXED CAPITAL INVESTMENT	51.6
Working Capital	2.6
TOTAL CAPITAL COST First Quarter 1978, Price and Wage Levels	54.2

TABLE 22. ANNUAL OPERATING AND MAINTENANCE COSTS* — WOOD TO POWER

Element	$1,000,000's
Supplies	0.1
Utilities	0.1
Operating Personnel	0.3
Maintenance Labor and Materials	0.2
Supervision	0.1
Administration and Overhead	0.3
Local Taxes and Insurance	1.1
TOTAL ESTIMATE ANNUAL OPERATING COST First Quarter 1978, Price and Wage Levels	2.2

*Excluding wood feedstock

TABLE 23. ANNUALIZED COST OF ELECTRICITY

Element	$1,000's	Mills/kWh (net)	$/MM Btu (net)
Annualized Capital Cost (9%)	5,247	19.0	5.57
Annual Operating Cost	2,200	8.0	2.33
Annual Feedstock Cost (Base: $10/ton)	4,770	17.3	5.07
TOTAL ANNUALIZED COST	12,217	44.3	12.97

WOOD-TO-POWER ENVIRONMENTAL ASSESSMENT

Feedstock procurement impacts and impacts of the operating plant are described in the context of the hypothetical location in the South Central Region of the U.S.

Residue Procurement Impacts

About 480,000 tons per year of residue will be removed from forestlands in the vicinity of the conversion plant. General impacts on land, water, air, and biological resources are described in this section. Specific impacts for a specific location would have to be assessed in an EIR or EIS for an actual biomass conversion project of this magnitude.

Forest Protection--

Residue collection and removal will serve as a forest-fire protection measure and will help to reduce the damage caused by insect pests and plant diseases spread by insects. These beneficial impacts will directly affect only those areas being harvested for residue; over the years a good portion of the forestland in the area will be affected and receive some benefit.

Forest Improvement--

Stand improvement can be aided by removing residues that impede germination and development of seedlings. However, complete residue removal may not be desirable since moist decayed organic matter can form seed beds for new growth and provide a nutrient supply to seedlings.

Soil Fertility and Erosion Control--

Plant nutrients contained in the residues will be removed through residue collection. The extent to which residues can be removed without causing serious deficiencies will depend upon the nutritive makeup of the soils in the area and the importance of residues in nutrient replenishment. Leaves, which are rich in nutrients, would normally be left on the forest floor. Partial harvesting of residue would be preferable to a complete harvesting which might require importation of fertilizers to maintain soil productivity.

Soil stability may be adversely affected by excessive removal of residues and disturbance of other ground cover by collection activities. Soil erosion on slopes and cuts could become a significant adverse impact without a well-managed harvesting program.

Water Quality--

Secondary impacts resulting from soil erosion may degrade the quality of local surface waters. Wind- and water-carried soils and forest residues in streams can adversely influence stream biology. Organic matter can increase biological oxygen demand and reduce the dissolved oxygen available for fish. Turbidity can impede fish migration, while heavy siltation can impede fish breeding, the hatching of eggs, and the survival of larvae. An increase in color and turbidity may make the streams less acceptable as surface water supplies.

Wildlife--
Removal of forest residue may be detrimental to some species of small mammals and birds inhabiting the forest lands. During collection activities, the wildlife habitats will be disturbed, forcing temporary displacement of these species into nearby areas. Displacement in habitats which already support the maximum populations possible (carrying capacity has been reached) usually results in mortality of the displaced species. This is particularly true of strongly territorial animals, which require a specific living space to breed and feed. Residue removal may also sufficiently disturb the habitats of some animals that repopulation of the disturbed area from the nearby populations is limited.

Recreation and Aesthetics--
Optimum removal of residues will usually improve the aesthetic appearance of logged areas and may enhance the recreational value of the forestland. Complete harvesting, which may cause severe soil erosion, displacement of animals, and other undesirable secondary impacts, would not be beneficial.

Transportation--
Wood harvesting in the forestlands and wood hauling to and from yarding sites will involve vehicles operating on and off local roads and highways. An average of about 100 truck loads or 40 rail carloads will be shipped to the plant each day -- most from yarding facilities. The additional traffic burden on roads and rail lines is expected to be small compared with the current vehicle-mileage or ton-mileage levels in the collection area (3000 to 4000 square miles). Local congestion may occur at times along principal haul routes to and from yarding sites and in the vicinity of the conversion plant.

Motor fuel consumption for residue collection will be on the order of two to three percent of the conversion plant's energy output and less than one percent of the delivered wood fuel energy content. Vehicle pollutant emissions will increase because of this additional fuel consumption, causing a small, adverse impact on ambient air quality. Hauling activities will also increase local fugitive dust emissions, especially on unsurfaced roadways.

Socioeconomics--
Feedstock collection will provide new employment opportunities in the area. Some 30 to 50 permanent jobs and additional part-time employment will be generated. Several million dollars ($4.8 million at $10/ton) of income will be added to the economy of the area through sale of residue to the plant owner. The magnitude of the collection operation is small enough to be accommodated by local manpower and community service resources.

Summary--
Forest residue procurement activities will have both positive and negative impacts on the environment of the area. Table 24 summarizes expected impacts and potential mitigating measures. Some social and economic benefits will be derived through increased employment. Residue removal itself can be beneficial to forest productivity, but detrimental to soil fertility, soil stability, and wildlife habitats. On balance, it appears that judicious residue removal through a careful collection management program can mitigate many of the potential adverse impacts.

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TABLE 24. PROCUREMENT IMPACT SUMMARY — FOREST RESIDUE

Environmental Factors	Residue Procurement Impacts	Potential Mitigating Measures
Air Quality	Minor adverse impact from vehicle combustion product emissions and localized fugitive dust emissions	
Surface Water Quality	Potential degradation of water quality resulting from soil erosion — increased siltation and organic loading of streams	Avoid or limit collection on unstable soils
Groundwater Quality	No discernible effect	
Land Availability	Abundant forestland in region; yarding requires small amount; agreements with owners needed for collection of enough residue for plant operation over 30-year life	Develop residue collection and management plan to ensure supply and minimize damage to forestland
Ecology and Critical Habitat	Some 30,000 to perhaps 100,000 acres of land subjected to residue collection each year; judicious collection can improve forest productivity, reduce fire and insect damage; some damage to vegetation during collection, disturbance of wildlife habitats and possible permanent loss of individuals of some species	Surveys needed to avoid critical habitats; management of collection activities to minimize damage of vegetation and wildlife
Soils and Geology	Plant nutrients in residue removed — can result in degradation of soil fertility and complete residual removal may cause serious deficiencies, potential adverse effect on soil stability in sensitive areas	Soil surveys and monitoring of collection activities to prevent significant damage to fertility and stability; import fertilizer, if necessary

(Continued)

TABLE 24. (Continued)

Environmental Factors	Residue Procurement Impacts	Potential Mitigating Measures
Aesthetic and Recreational Resources	Improvement in appearance of logged areas; potential increase in recreational value	
Community Economy	Significant benefit to local economy through plant purchase of delivered forest residue — $4.8 million annual input	
Community Population and Services	Little increase expected in local population and in demands for services	
Labor Availability	Full-time and part-time jobs will be created by procurement activities; local manpower resources are adequate and will benefit from jobs	
Transportation	Small increase in rail and road traffic in region; local congestion may occur on principal haul routes at times	

Plant Impacts

The wood-to-power plant will have impacts on the environments which are normally categorized as physical/chemical, biological, socioeconomic, and aesthetic in nature. Of these, the physical/chemical impacts will be given the most attention since they primarily involve direct emissions to the environment. Construction and operation of the plant will also involve the commitment of physical resources. It is assumed that the total plant construction period will be three years with field construction predominating during the last two years. The plant will be operated for 30 years.

Table 25 summarizes the major resources utilized in operating the plant. Table 26 summarizes annual chemical requirements.

TABLE 25. PRINCIPAL RESOURCES COMMITTED TO PLANT OPERATION

Resource Category		Normalized Quantity (Output)*
Land	50 acres	1.11 ac/MWe
Feedstock (Wood Residue)	477,207 tons/yr	3.46 lb/kWh (15,790 Btu/kWh)
Auxiliary Fuel	52 MMM Btu/yr	188 Btu/kWh
Chemicals (Total)	64 tons/yr	0.00046 lb/kWh
Auxiliary Power Consumed	30.2 MM kWh/yr	0.109 kW/kW
Water	266 MM gal/yr	0.82 gal/kWh
Manpower (30 employees)	60,000 manhours/yr	0.67 men/MWe

*Basis 275.9 MM kWh/yr net output

Physical/Chemical Emissions and Impacts--

Air Emissions--Emissions of pollutants to the atmosphere from the plant site are not expected to significantly degrade ambient air quality with respect to the five designated pollutants (particulate matter, sulfur oxides, nitrogen oxides, carbon monoxide, and photochemical oxidants). Table 27 summarizes major emission sources and estimated pollutant emissions. The boiler stack and the cooling tower exhaust will be the two largest point sources of discharge in terms of flow. Wood chip transfer operations will be the primary sources of fugitive dust emissions (particulate matter).

TABLE 26. SUMMARY OF ANNUAL CHEMICAL REQUIREMENTS — WOOD TO POWER

Chemical	Amount Per Year
Sulfuric acid (66^{o} Be)	30 tons
Caustic Soda (50%)	17 tons
Chlorine	8 tons
Lime	5 tons
Cleaning Chemicals (HCl, Citric Acid, and Soda Ash)	5 tons
Dispersant (Phosphate)	1 ton
Miscellaneous BFW Chemicals	0.5 ton
Ion Exchange Resins	10 cu ft
Lube Oil	2,000 gal
Auxiliary Fuel	
Diesel	50,000 gal
Gasoline	13,000 gal
Natural Gas	44,000 MSCF

TABLE 27. SUMMARY OF ESTIMATED AIR EMISSIONS — WOOD TO POWER

Emission Source	Estimated Flow	Pollutants	Emission Rate
Boiler Stack (175 feet high)	856,300 lb/hr, 196,300 SCFM total flow	Particulate matter	2 lb/hr(a) 0.003 lb/MM Btu
		SO_x	<3 lb/hr(b)
		NO_x	356 lb/hr(c)
		CO	71 lb/hr(d)
		HC	71 lb/hr(e)
		Thermal	185 MM Btu/hr at 300°F
Cooling Tower Exhaust	12 MM lb/hr (dry air)	Water droplets (drift)	4,400 lb/hr
		Salts (in drift)	∿5 lb/hr
			333 MM Btu/hr(added)
Wood Chip Dump Hopper	2000 tons/day of chips unloaded	Fugitive dust	100 lb/day (0.05 lb/ton)
Chip Storage Pile	56,000 tons stored (3-4 acres)	Fugitive dust	22 lb/day (1 ton/yr/acre)
Chip Transfer Bins	2000 tons/day chips 1.8 MM CFD vent gas	Fugitive dust	3 lb/day (0.01 gr/CF after collector)
Pneumatic Conveyors	2000 tons/day chips 6.7 MM CFD air flow	Fugitive dust	960 lb/day (0.1 gr/CF)
Boiler Feed Bin	2000 tons/day chips 1.6 MM CFD vent gas	Fugitive dust	3 lb/day (0.01 gr/CF after collector)
Miscellaneous	Plant area and roads	Fugitive dust	small
	Mobile equipment exhausts	Combustion products	small
	Fuel Storage tanks	Hydrocarbon vapors	small

(a) Based on 99.5 percent reduction.
(b) Based on 0.01 percent sulfur in fuel.
(c) Estimated as 0.5 lb NO_2/MM Btu input.
(d) Estimated as 0.1 lb CO/MM Btu input.
(e) Estimated as 0.1 lb/MM Btu input.

The boiler stack gas is expected to meet the proposed stationary source NSPS for particulate matter and sulfur oxides. The new standard for particulate matter (99 percent reduction of uncontrolled emissions) requires high-efficiency collectors regardless of the level of uncontrolled dust loading. The gas cleanup system will include a mechanical collector ahead of, and to protect, the air heater and an electrostatic precipitator for final cleanup. Flyash reinjection will also be practiced. Overall removal efficiency is expected to be 99.5 percent. Particulate matter emissions are expected to be considerably lower than the proposed limit of 0.03 lb/MM Btu heat input in part because of the low ash content of the wood. Similarly, sulfur oxide emissions are expected to be low because of the low (trace quantity) sulfur content of the wood. No sulfur oxide (SO_2) removal system will be needed because uncontrolled emissions will be less than 0.2 lb SO_2/MM Btu heat input (above this limit, 90-percent removal would be required by the proposed regulation).

Emissions of nitrogen oxides (NO_2), carbon monoxide (CO), and unburned hydrocarbons (HC) are less easily estimated and are related to boiler design and combustion conditions. Fuel nitrogen content is low and would contribute little to NO_2 emissions. The high excess air rate which promotes air nitrogen fixation would be somewhat offset by moderate combustion temperatures. It is possible that the 0.6 lb NO_2/MM Btu input standard would be met with good combustion control. (Sixty-five percent reduction of uncontrolled emissions may not be achieved.) Similarly, CO and HC emissions should be low with good combustion control and high excess air flow. The ash reinjection system should help to reduce the emission of unburned carbon particles. The estimates in Table 27 are about one-half those indicated as emission factors (lb emission/ton fuel burned) for wood and bark combustion in a recent EPA report (20).

Emissions of hazardous materials, i.e., carcinogenic organics and heavy metals, are not expected to be significant, either in concentration in the fluegas or in effects on public health.

The cooling tower will discharge nearly 100 MW of thermal power to the atmosphere and will evaporate nearly 250,000 lb/hr of water. The heat load and water vapor do not normally constitute pollutants, and impacts on the local air quality and climate will be insignificant. However, a visible and persistent plume could occur at times, particularly if the ambient humidity is high, and could constitute an aesthetic impact.

Cooling-tower drift loss will be on the order of two tons per hour of water in droplet form. About 15 tons per year of salts contained in the drift could be deposited on the ground in the vicinity of the tower. These salts could affect sensitive plant species directly through leaf burn, or indirectly through buildup in the soil.

Fugitive dust emissions will result from handling the wood chip fuel within the plant. The suspendible particulate matter content of the wood is unknown. However, it is likely that most of the particulate matter emitted from wood handling will be settleable and drop to the ground near the source. Emission of dust will be low from bin vents equipped with fabric filter collectors. Wind-blown dust and perhaps chips from the chip storage pile may be a local

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nuisance at times. A relatively large surface area (three to four acres) will be exposed to the wind. Movement of the bulldozer on the pile will tend to compact the surface layer and help retard surface erosion. Most of the windblown material will resettle on the pile itself. However, some will be distributed on the ground near the pile and the smaller (suspendible) material could be carried offsite.

Pollutant emissions to the air will have two principal kinds of impact: effects on the air quality, and effects on biota. Air-quality degradation in the vicinity of the plant is expected to be minor overall. Emissions of NO_x, CO, and HC will have some, though perhaps not measurable, adverse impact on the air quality. Emissions of heat and water vapor will probably be too low to cause any perceptible modification of the climate in the area. Plant and animal life in the vicinity will suffer little damage from plant air emissions (see Biological Impacts).

The plant would be considered a new major source and hence could be subject to the current "offset" policy if located in a nonattainment area. Namely, the plant would be responsible for reducing emissions from existing sources in the area to offset its own (controlled) emissions (NO_x about 1000 tons/yr, CO and HC about 200 tons/yr each).

Water Emissions--The plant will discharge about 100 gpm of process wastewater to the river from which the plant withdraws water. In general, the wastewater will contain the same constituents (and quantities) present in the river water supply plus chemicals added to this water in the plant. The added chemicals represent the principal pollutant load contributed by the plant -- primarily dissolved and suspended solids. Table 28 summarizes the estimated wastewater emissions.

Over one-half of the process effluent is water related to the steam cycle section of the plant. Boiler blowdown, feedwater treatment brines, and cooling-tower blowdown are essentially purges of undesirable dissolved and suspended solids. Boiler blowdown is concentrated boiler feedwater containing small concentrations of chemical additives. Regenerant brines contain sodium and sulfate ions (added as NaOH and H_2SO_4 in the regeneration cycle) and the anions and cations removed from the river water in the ion exchange treatment process. Cooling-tower blowdown is essentially river water concentrated by evaporation. Sulfuric acid, a phosphate dispersant, and chlorine are added to control scaling and fouling in the cooling system. By the concentration process alone, the blowdown will also contain fairly high concentrations of those chemicals present in the river water (see Table 18). After settling treatment, the blowdown effluent will contribute mainly dissolved solids (from chemical additions) as a pollutant load to the river.

Stormwater runoff will be the single, intermittent source of effluent that does not originate from the river. Runoff will pick up silt and may leach or wash off some inorganic and organic materials through contact with various surface areas in the plant. Confined yard and floor drainage will be skimmed of any free oil and settled for suspended solids removal. Storm runoff will also be collected and settled for suspended solids removal. Normal process wastewater and treated sanitary waste will contribute some small quantities

TABLE 28. SUMMARY OF ESTIMATED WASTEWATER EMISSIONS — WOOD TO POWER

Source	Estimated Flow	Pollutants	Emission Rate
Boiler Blowdown	19 gpm	Total dissolved solids (TDS)(80 mg/l)	3.4 lb/day
		Total suspended solids (TSS)(20 mg/l)	0.8 lb/day
		pH (alkalinity reduced by blending)	6-9
Regenerant Brines	Intermittent, 2400 gal/day	TDS (7500 mg/l)	150 lb/day(a)
		Acidity/alkalinity-neutralized	—
		pH	6-9
Cooling Tower Blowdown	46 gpm (10 cycles of conc.)	TSS (30 mg/l)	16 lb/day(b)
		TDS (1150 mg/l)	635 lb/day
		Chlorine (residual <0.1 mg/l)	<.05 lb/day
		pH	6-9
Yard and Floor Drains	30 gpm	Oil & Grease (10 mg/l)	3.6 lb/day
		TSS (20 mg/l)	7.2 lb/day
		pH	6-9
Sanitary Waste	5 gpm	BOD (25 mg/l)	1.5 lb/day
		TSS (10 mg/l)	0.6 lb/day
		Coliforms (<200 MPN/100 ml)	—
		pH	6-9
Chemical Cleaning Wastes	Intermittent, 100,000 gal/cleanout	Acidity — neutralized	—
		TSS (50 mg/l)	42 lb/batch
		TDS (10,000 mg/l)	8330 lb/batch
		pH	6-9
Storm Drainage	Intermittent, 46.5 gpm annual avg.	Oil & Grease (<5 mg/l)	2.8 lb/day
		TSS (<50 mg/l)	2.8 lb/day
		pH	6-9

(a) 123 lb/day of Na^+ & SO_4 added.
(b) 185 lb/day of SO_4 = $NaPO_3$ and Cl^- added.

of pollutants to the receiving water. The plant effluent will have a minor adverse impact on receiving water quality; it is unlikely that any resulting changes in river quality will be detectable.

Plant water consumption (about 617 gpm) will be a small fraction of the total river flow. This consumption will have a very small impact on surface water resource availability, and no impact on groundwater resources.

Solid Waste Emissions--The two major solid wastes generated by the plant will be furnace ash and general plant trash (see Table 29). Intermittent (and infrequent) wastes will be sludges from basin, pond, and cooling tower cleanouts. All wastes will be buried in an approved onsite landfill. About 5½ tons of moist wood ash will be buried each day. This ash is expected to be rich in minerals, be somewhat alkaline, and contain trace concentrations of a number of heavy metals. Plant trash and garbage will be collected and buried less frequently. The burial site will be operated much like a sanitary landfill, with proper care taken to prevent leachate formation, litter blowing, burrowing of rodents, and other nuisances.

TABLE 29. SOLID WASTE DISPOSAL SUMMARY — WOOD TO POWER

Source	Estimated Quantity	Potential Pollutants	Disposal
Boiler Ash	390 lb/hr wood ash and grit 69 lb/hr moisture (15%)	Alkalinity, trace metals	Ash moisturized (15% H_2O) and buried in landfill - about 480 cu ft/day
Plant Trash and Garbage	150 lb/day	Decomposable waste, some oily materials	Collected twice per week and buried - about 30 cu ft/day

The major impact of solid waste emissions will be the utilization of about five acres of land over the plant life. With proper operation of the landfill, there should be little damage to the environment in terms of degradation of air quality and surface and ground water qualities. The size of the landfill could be reduced by using some or all of the wood ash as a soil amendment.

Soils and Geology--Approximately 40 acres of land surface will be altered during construction of the plant. Although most of the site is fairly level, earthwork will involve clearing and grading, including some cut and fill areas and excavation for basins and foundations. The application of construction materials for foundations and roadways will further change the physical surface.

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Site topography, drainage patterns, and soils will be permanently altered during construction. Burial of boiler ash will also increase the height of the five-acre landfill site by 20 to 25 feet over the plant operating life.

Although the physical changes in the land surface could be considered as a localized adverse impact, the site is similar to other sites in the region (no uniquely distinguishing features), and no significant regional impacts are anticipated.

Biological Impacts--

Construction and operation of the plant will have primary and secondary impacts on biological species in the vicinity. As a direct result of site preparation, 50 acres of vegetation and the associated wildlife on the site will be removed or disturbed. Wildlife in nearby habitats may also be affected by construction activities, particularly by construction noise. Sensitive species will leave the area, but some may return during the plant operation phase. Others may adapt to the increased noise levels and human presence and may suffer only temporary discomfort. The plant fence will be a barrier to the movement of larger animals onto and off the site. Careful plant siting would avoid disturbances or destruction of rare, unique, or endangered species of vegetation and wildlife, and ensure that all of the vegetation and wildlife types present on the plant site are well represented in other areas of the region.

Other seondary biological impacts result from changes in air, water, or soil qualities. Secondary impacts resulting from construction activities will be temporary and different from those resulting from plant operation. Local damage to plant species along roadways could occur from deposition of high concentrations of dust on leaves. Changes in offsite drainage patterns due to construction-site work may result in some local areas of soil erosion and consequent damage to vegetation. Sediment loadings in surface waters may increase because of runoff from construction areas, resulting in temporary stress or damage to aquatic plants and animals. With proper construction planning and management, these secondary impacts can be minimized.

As noted earlier, air and water emission from operation of the plant will have minor adverse impacts on air and water qualities. Secondary effects on biological species resulting from these adverse impacts are expected to be minor. Since emissions will be relatively continuous over the conversion plant life, long-term exposure may result in damage to plants and animals because of the cumulative effect. For example, some plant species are sensitive to increases in nitrogen oxide concentrations. Plants downwind of the boiler stack may be exposed to higher than normal (ambient) NO_x levels over a long period and may suffer some leaf damage. Generally, the plume will be well enough dispersed and high ground-level concentrations will occur only during short-term adverse meteorological conditions.

The cooling-tower drift will deposit salts on the ground downwind of the tower. A localized increase in soil salinity may damage some less tolerant species.

Any damage to aquatic species as a result of plant wastewater emissions will probably be confined to a localized area near the discharge point.

A combination of good river water quality and the low emission of pollutants is expected to result in little harm to plant and animal life outside of the mixing zone. Some small organisms will be withdrawn from the river (entrained) in the intake water, and most will be destroyed in the plant water systems. Screens in the intake pump house will prevent the entrance of larger species such as fish.

Overall, the major biological impact will be the direct removal of plants and animals from the site during plant construction and the loss of productive farmland, but this impact is not expected to be significant to the region.

Aesthetic Impacts--
Visually, the conversion plant will contrast with the rural surroundings. Local relief is low and taller plant structures will be visible from a considerable distance. As viewed from the access road approach to the hypothetical plant, the turbine building, the boiler precipitator, and the 175-foot high stack will appear as a dominant cluster of tall structures on a level ground area, with the wood chip pile appearing as a large, rather regular light-colored mound (about 40 feet high) in the background. The cooling tower and its characteristic white plume will be most visible at angles away from the prevailing wind direction. The plant itself is small and so should not be as striking visually as some large power plants, especially those with natural-draft cooling towers which can visually dominate almost any natural topographical feature. The overhead transmission line, the switchyard, and the rail facilities will generally be considered as detrimental to the aesthetic quality of the area, as might other plant structures.

Adverse impacts on aesthetics can be mitigated somewhat through plant and building design, site layout, and landscaping. Landscaping the undeveloped plant grounds along roads and fence lines will help to mitigate or obscure the contrast between the structures and the level surroundings. However, on balance, the plant will probably have a negative effect on the aesthetic quality of the site as perceived by local residents and some visitors.

Social and Economic Effects--
The capital investment ($54 million total) in the plant and annual operational expenditures will stimulate the local economy. Temporary jobs will be created for several hundred construction workers, and about 30 permanent jobs for operating employees will result. Income from these jobs will result in increased spending in nearby towns. Average income in the region is below the national average and a new source of employment would probably be welcomed. Some portion of the capital investment for equipment and materials will also be expended in nearby communities. The local industrial tax base will also be expanded, and the taxes will provide additional community services.

Plant operating labor and most of the construction workforce can be obtained from the unskilled and skilled labor pools in the region. Little increase in local population is anticipated as a direct result of the conversion plant construction. Demands on community services will be highest during construction; however, it is likely that any needed expansion of services could be accommodated without significant economic impact on the community. Economic benefits derived from taxes, wages, and spending in the community will outweigh to some extent the adverse impact of increased demands on local services during construction and operation. The plant itself will generate power to meet the new electrical demands of residential, business, and industrial consumers, and will permit a further expansion of the economy of the region.

As a summary, Table 30 lists principal plant impacts discussed above and potential mitigating measures.

COAL-TO-POWER PLANT SITE DESCRIPTION

The hypothetical site for the coal-fired power plant is similar to that for the wood-to-power plant, though larger in size. The 365-acre fenced site is on gently rolling farmland and woodland about one mile from a navigable river. A buffer zone of equal acreage is assumed to surround the site. All topographic, climatic, hydrographic, biologic, and demographic conditions are also similar.

The plant owner is assumed to construct a coal-barge unloading facility on the river bank, to install structures for water intake (pumphouse and supply pipelines to the plant) and discharge (discharge pipeline and submerged diffuser section in the river), to construct an all-weather access road and a rail spur to the plant site. Underground transmission lines (345 kV) from the plant switchyard to the plant fence line are also within the scope of the project. Connection to a regional utility grid is by others.

The site is in Seismic Zone 1. The air quality region is currently listed as a nonattainment area for photochemical oxidants.

COAL PROCUREMENT

In this scenario, approximately one million tons per year of coal is shipped to the power plant from surface mines in the northern part of the state. In 1975, more than nine million tons of strip-mined coal were produced in three contiguous counties, one of which is assumed to be the hypothetical source of coal for the plant (21). Strippable reserves in these counties exceed 100 million tons. The plant receives 1¼-inch by 0 (primary and secondary crushed) coal by barge from a mining company on a long-term contract basis. A brief description of the mining and transport operation is presented for comparison with forest residue collection.

The plant feedstock is classified generally as high volatile-B bituminous coal. More than one site may be mined over the plant life and part of the production from more than one mine might reasonably be shipped to the plant. Coal production is a completely separate operation from that of the power plant. In this case, the production from two strip mines is dumped in a common area. Part of the run-of-mine (ROM) coal is crushed, loaded on barges, and shipped downriver to the plant. Total production is four to five million tons per year.

The mining area is typically hilly terrain, hilltops locally to 600 feet elevation. Several strip mines on either side of the river are active, while

TABLE 30. SUMMARY ENVIRONMENTAL MATRIX — WOOD TO POWER

Environmental Factors	Effect of Plant Construction and Operation	Potential Mitigating Measures
Climatology and Meteorology	No discernible impact, discharged heat and water vapor not expected to have noticeable effect on climate	
Air Quality	Potential localized impact of fugitive dust from construction; small adverse impact from plant operation	
Surface Water Availability	Requires about 1 gal/kWh of energy output; minor adverse impact of water resources	
Surface Water Quality	Minor adverse impact on quality	
Groundwater Availability	No consumption; no effect	
Groundwater Quality	Low potential for contamination	Ponds and basins lined; proper management of landfill required
Land Availability	Requires about 50 acres of land; no significant impact	Careful siting to avoid sensitive areas
Regional Ecology and Critical Habitat	About 40-50 acres of vegetation removed and associated wildlife displaced or destroyed during construction; minor adverse impact, potential — low indirect impacts during construction and operation	Careful siting to avoid critical wildlife habitats and rare or endangered biological species

(Continued)

TABLE 30. (Continued)

Environmental Factors	Effect of Plant Construction and Operation	Potential Mitigating Measures
Aesthetic Resources	Small to moderate negative impact-appearance conflicts with farmland/woodland surroundings	Plant design, layout and landscaping
Historical, Archaeological Resources	Insignificant impact	Siting surveys to protect cultural resources
Community Economy	Substantial benefit from construction and operation through broadened tax base, wages paid into community	
Community Population and Services	Minor increase in local population and residential services; minor adverse impact on community resources	
Labor Availability	Requirements for 200-300 construction and about 30 operation personnel; local manpower resources adequate	Plant to train unskilled workers as necessary
Power Availability	Temporary power source needed for construction, plant will export power to local grid (power transmission facilities supplied by power purchaser)	
Transportation Availability	Requirement for construction of access road and rail spur; small adverse impact on environment from new transportation corridors (and transmission corridor)	Careful selection of corridors to minimize impacts on land use; ecology and water resources

other sites have been mined out and abandoned. Mined coal is typically hauled either to the river or to rail lines for shipment. On the site, the overburden ranges from zero feet at outcrops to about 100 feet at the maximum. The coal seam averages six feet. Vegetation is cleared and topsoil is stripped and stockpiled. Then the overburden is drilled (high-wall drill, electric crawler) and blasted with an ammonium nitrate-fuel oil mixture. Large electric shovels and a dragline remove the overburden and deposit it in spoils banks. Bulldozers are used to support the drilling and stripping operations. With the seam exposed, electric shovels excavate the coal and load 120-ton bottom-dump trucks. Front-end loaders are used for cleanup and auxiliary loading. The trucks haul coal over temporary roads from the active mining areas to the dump site near the river. New haul roads are constructed as needed to provide off-highway access from the mine to the coal dumping area. Most of the coal is recovered by area mining, although some contour stripping is done at outcrops on steep hills.

At the coal dump-loading site, run-of-mine coal is prepared for shipment. Trucks dump the coal into a receiving hopper equipped with grizzly bars to reject oversize material. An ROM storage pile is provided as an alternate dump site. A reciprocating feeder feeds coal to a vibrating grizzly. Plus 6-inch material is crushed in a rotary breaker. Minus 6-inch material from the grizzly is combined with breaker product and fed to another vibrating grizzly. Plus 1¼-inch material is sent to a double roll crusher for size reduction to 1¼-inch by 0. Crusher product is combined with minus 1¼-inch coal from the grizzly and conveyed to a storage pile near the barge loading facility. Under-pile feeders and a 48-inch reclaim conveyor transfer coal to the barges. The coal passes over a belt scale, onto a hinged boom, and through a revolving chute that spreads coal evenly into barges 175 feet long by 26 feet wide. The discharge end of the hinged boom can be adjusted to allow for differences in water level and barge height during loading. Coal tows of five to 15 barges (5,000 to 15,000 tons) are moved downriver to the power plant.

As areas of the coal seam are mined out, the surface reclamation process is initiated and carried on concurrently with mining. Overburden is backfilled in the mined area by dragline and bulldozers. Bulldozers and graders contour the surface to gently rolling terrain (also striking off the tops of spoil ridges). Stockpiled topsoil is transported by carryalls and is spread over the slopes by a bulldozer and a grader. Prior to seeding, the soils are tested to determine nutrient levels. Revegetation species are standardized in the state (forest, grasses, and legumes). In this area, pine seedlings and native grass seed mixtures are used predominantly. Surface mine soils tend to be somewhat acid and low in potassium content. Approximately 100 to 150 acres of land are stripmined each year to provide the coal production for the power plant. More land would be disturbed and require reclamation if, as has been assumed, the hypothetical mining company supplied coal to other users of both steam and metallurgical coal.

COAL-TO-POWER PROCESS DESCRIPTION

The 500 MWe power plant is assumed to be owned by a regional utility producing power for transmission at 345 kV to its utility grid. Cleaned and sized coal (minus 1¼-inch) is purchased on a contract basis and delivered to the plant's dock facilities by standard coal barges (1000-ton capacity). The single-unit generating station has a nonregenerable flue gas desulfurization (FGD) system to comply with the proposed new source performance standards (NSPS) for the coal-fired steam-electric generating category. The plant has a nameplate rating of 508 MW and produces about 476 MWe net output at 100-percent load and average conditions. Coal consumption is about one million tons per year. The general plant layout is illustrated in Figure 11.

Design Basis

The conceptual plant design is intended to be representative of commercial-size units that are currently being constructed or being planned by utilities in the U.S. This case considers only a single unit station, whereas two or more unit stations in sequenced construction are becoming more common. No provisions (or costs) were included for a second unit, however. The scenario area is a developing industrial and commercial region and the increased demand for power justifies the need for the facility. Abundant coal resources available in the region can support many more stations of this size.

Table 31 presents the composition of the assumed coal feedstock for the plant. The high volatile-B bituminous coal contains about 1.5 percent sulfur and hence cannot be burned without flue gas cleanup for sulfur oxides removal.

Table 32 presents general design bases assumed for the conceptual plant.

The process description is broken down into major sections: coal handling, combustion, flue gas cleanup, steam-turbine cycle, and auxiliaries, including water and wastewater treatment and solid disposal systems. Figure 12 is a simplified process flow diagram of the plant.

Coal Handling

The coal-handling facilities include the coal unloading dock, an overload conveyor to the coal yard, an alternative car unloading dump, the live and dead coal storage, the reclaim system, and the impact cascade system feeding the boiler silos.

One-thousand-ton barges of coal are unloaded one shift per day, six days a week, an average of five barges per day. Barges are unloaded by an inclined-boom continuous bucket unloader. Three rows of buckets extend the full width of the barge.

The barges are spotted by a tug in the unloading area. The bucket reclaimer discharges coal into a 50-ton surge bin on the elevated dock structure. Unloading capacity is 2000 tons per hour. An apron feeder loads a 42-inch wide belt conveyor which transports the coal at 1000 tons per hour, a distance of 3000 feet to a transfer house and sample station. The overland conveyor is fully enclosed to prevent windblown loss of coal. A belt scale is located near the feed end of the conveyor. At the transfer house, coal is discharged into a chute which feeds a 42-inch stacker feed conveyor. A magnetic separator above the belt removes tramp iron. A two-stage sampling system removes

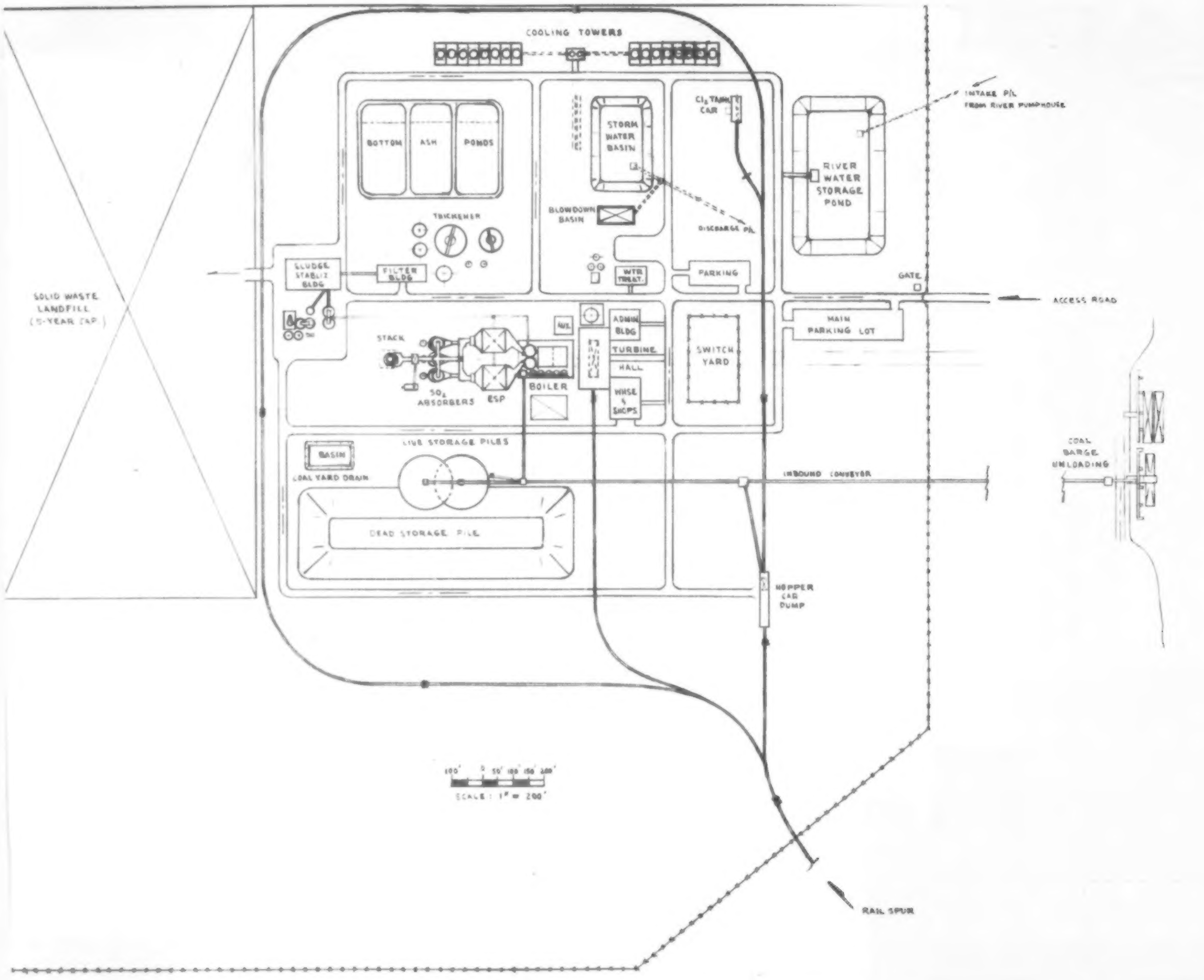
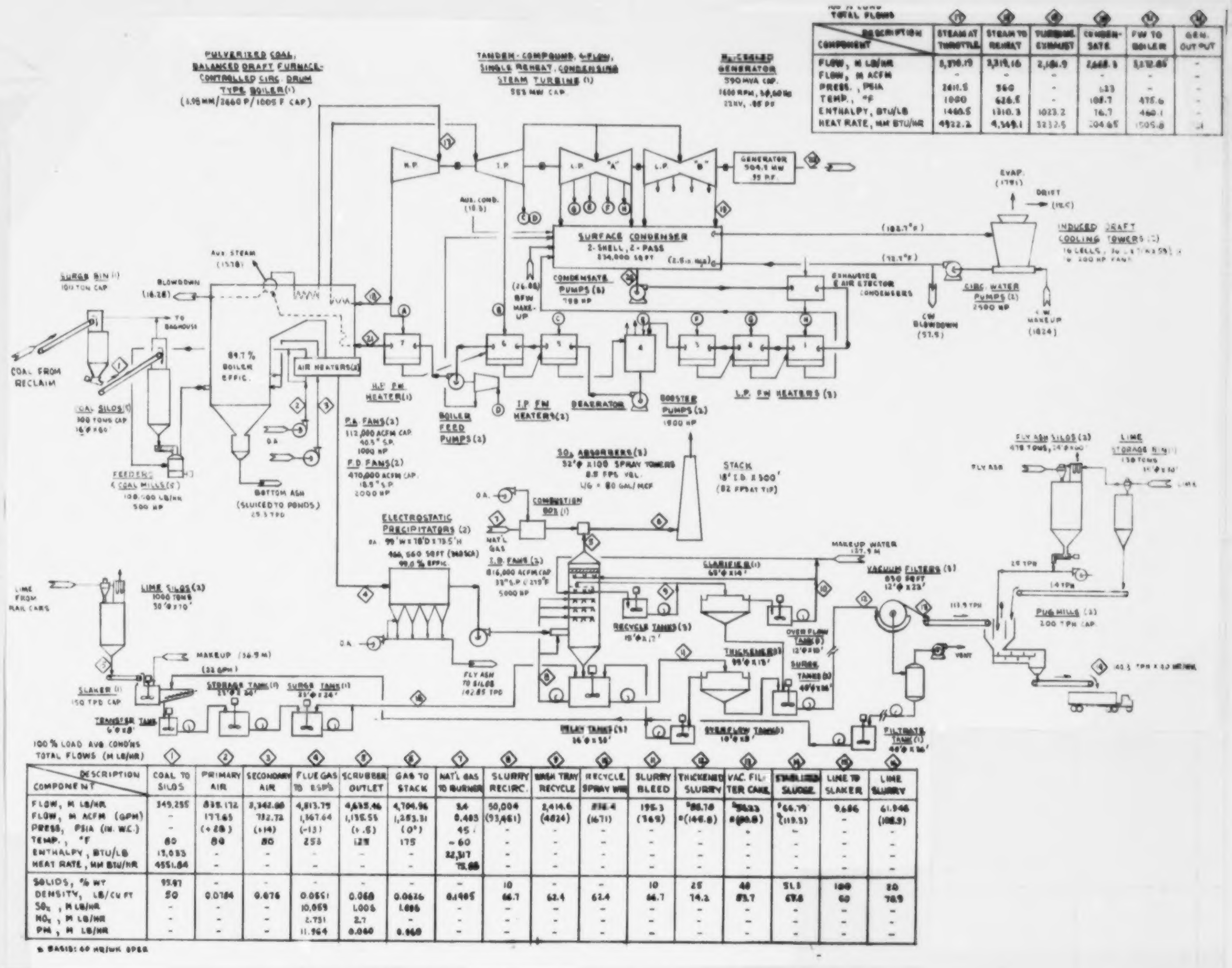

COOLING TOWERS
BOTTOM
ASH
PONDS
THICKENER
STORM WATER BASIN
BLOWDOWN BASIN
Cl_2 TANK CAR
DISCHARGE P/L
INTAKE P/L FROM RIVER PUMPHOUSE
RIVER WATER STORAGE POND
SLUDGE STABLIZ BLDG
FILTER BLDG
WTR TREAT.
PARKING
GATE
ACCESS ROAD
SOLID WASTE LANDFILL (5-YEAR CAP.)
STACK
SO_2 ABSORBERS
ESP
AUX.
BOILER
ADMIN BLDG
TURBINE
HALL
WHSE & SHOPS
SWITCH YARD
MAIN PARKING LOT
COAL BARGE UNLOADING
BASIN
COAL YARD DRAIN
LIVE STORAGE PILES
INBOUND CONVEYOR
DEAD STORAGE PILE
HOPPER CAR DUMP
100' 0 50' 100' 150' 200'
SCALE: 1" = 200'
RAIL SPUR

Figure 11. Coal-fired power plant, general plant layout.

TABLE 31. ASSUMED COAL FUEL PROPERTIES

Composition	Moisture Free	As Received
Proximate		
Volatile Matter, % wt	38.4	-
Fixed Carbon, % wt	57.4	-
Ash, % wt	4.2	-
	100.0	
Ultimate		
Hydrogen, % wt	5.5	5.27
Carbon, % wt	76.3	73.17
Sulfur, % wt	1.5	1.44
Nitrogen, % wt	1.7	1.63
Oxygen, % wt	10.8	10.36
Ash, % wt	4.2	4.03
Moisture, % wt	-	4.10
	100.0	100.00
Heating Value (HHV), Btu/lb	13,590	13,033
Bulk Density, lb/cu ft	-	50


PULVERIZED COAL, BALANCED DRAFT FURNACE-CONTROLLED CIRC. DRUM TYPE BOILER(1) (3.95MM/2660 P/1005 F CAP)
TANDEM-COMPOUND, 4-FLOW, SINGLE REHEAT, CONDENSING STEAM TURBINE (1) 553 MW CAP.
H2-COOLED GENERATOR 590 MVA CAP. 1800 RPM, 3Ø,60 Hz 22KV, .85 PF
GENERATOR 504.1 MW .95 P.F.
H.P.
I.P.
L.P. "A"
L.P. "B"
AUX. COND. (10.5)
SURFACE CONDENSER 2-SHELL, 2-PASS 334,000 SQFT (2.5 in. Hga)
(26.88) BFW MAKE-UP
CONDENSATE PUMPS (3) 700 HP
EXHAUSTER & AIR EJECTOR CONDENSERS
(102.7°F)
(72.7°F)
EVAP. (1791)
DRIFT (15.C)
INDUCED DRAFT COOLING TOWERS (2) 16 CELLS, 36 x 17 x 58 x 16 200 HP FANS
CIRC. WATER PUMPS (2) 2500 HP
CW BLOWDOWN (57.5)
C.W. MAKEUP (1824)
AUX. STEAM (1578)
BLOWDOWN (16.28)
SURGE BIN (1) 100 TON CAP
TO BAGHOUSE
COAL FROM RECLAIM
COAL SILOS (5) 300 TONS CAP 16'Ø x 60'
FEEDERS & COAL MILLS (5) 100,000 LB/HR 500 HP
89.7% BOILER EFFIC.
AIR HEATERS (2)
O.A.
BOTTOM ASH (SLUICED TO PONDS) 25.5 TPD
H.P. FW HEATER (1)
BOILER FEED PUMPS (2)
I.P. FW HEATERS (2)
DEAERATOR
BOOSTER PUMPS (2) 1500 HP
L.P. FW HEATERS (3)
P.A. FANS (2) 112,000 ACFM CAP. 40.5" S.P. 1000 HP
F.D. FANS (2) 470,000 ACFM CAP. 18.5" S.P. 2000 HP
ELECTROSTATIC PRECIPITATORS (2) EA. 99'W x 78'D x 73.5'H 466,560 SQFT (340SCA) 99.0% EFFIC.
O.A.
FLY ASH TO SILOS 142.85 TPD
COMBUSTION BOX (1)
NAT'L GAS
I.D. FANS (2) 816,000 ACFM CAP 33" S.P. @ 279°F 5000 HP
SO2 ABSORBERS (3) 32'Ø x 100 SPRAY TOWERS 8.5 FPS VEL. L/G = 80 GAL/MCF
STACK 18' I.D. x 500' (82 FPS AT TIP)
RECYCLE TANKS (3) 15'Ø x 17'
CLARIFIER (1) 65'Ø x 14'
MAKEUP WATER 127.9 M
OVERFLOW TANK (1) 12'Ø x 10'
THICKENERS (2) 95'Ø x 15'
SURGE TANKS (2) 40'Ø x 16'
BLEED TANKS (3) 36'Ø x 30'
OVERFLOW TANK (1) 10'Ø x 8'
VACUUM FILTERS (3) 850 SQFT 12'Ø x 23'
FILTRATE TANK (1) 40'Ø x 36'
VENT
113.9 TPH
FLY ASH SILOS (2) 478 TONS, 24'Ø x 60'
FLY ASH
LIME STORAGE BIN (1) 130 TONS 14'Ø x 30'
LIME
25 TPH
1.4 TPH
PUG MILLS (2) 200 TPH CAP.
140.3 TPH x 60 HR/WK
LIME FROM RAIL CARS
LIME SILOS (2) 1000 TONS 30'Ø x 70'
MAKEUP (36.9 M)
(22 GPM)
SLAKER (1) 150 TPD CAP
TRANSFER TANK 6'Ø x 8'
STORAGE TANK (1) 23'Ø x 24'
SURGE TANK (1) 23'Ø x 24'
A
B
C
D
E
F
G
H

100 % LOAD
TOTAL FLOWS

DESCRIPTION / COMPONENT	17 STEAM AT THROTTLE	18 STEAM TO REHEAT	19 TURBINE EXHAUST	20 CONDEN-SATE	21 FW TO BOILER	22 GEN. OUTPUT
FLOW, M LB/HR	3,370.19	3,319.16	2,184.9	2,668.1	3,272.85	-
FLOW, M ACFM	-	-	-	-	-	-
PRESS., PSIA	2411.5	560	-	1.23	-	-
TEMP., °F	1000	626.5	-	108.7	475.6	-
ENTHALPY, BTU/LB	1460.5	1310.3	1023.2	76.7	460.1	-
HEAT RATE, MM BTU/HR	4922.2	4,349.1	3232.5	204.65	1505.8	[illegible]

100 % LOAD AVG COND'NS
TOTAL FLOWS (M LB/HR)

DESCRIPTION / COMPONENT	1 COAL TO SILOS	2 PRIMARY AIR	3 SECONDARY AIR	4 FLUE GAS TO ESP'S	5 SCRUBBER OUTLET	6 GAS TO STACK	7 NAT'L GAS TO BURNER	8 SLURRY RECIRC.	9 WASH TRAY RECYCLE	10 RECYCLE SPRAY WIR	11 SLURRY BLEED	12 THICKENED SLURRY	13 VAC. FILTER CAKE	14 STABILIZED SLUDGE	15 LIME TO SLAKER	16 LIME SLURRY
FLOW, M LB/HR	349.255	835.172	3,342.08	4,813.75	4,635.46	4,704.96	3.4	50,004	2,414.6	836.4	195.3	^{a}88.70	^{a}58.33	^{a}66.79	9.686	61.946
FLOW, M ACFM (GPM)	-	177.65	732.72	1,367.64	1,135.55	1,253.31	0.483	(93,461)	(4824)	(1671)	(369)	^{a}(146.8)	^{a}(90.0)	^{a}(119.3)	-	(108.9)
PRESS, PSIA (IN. W.C.)	-	(+28)	(+14)	(-13)	(+.5)	(0")	45	-	-	-	-	-	-	-	-	-
TEMP., °F	80	80	80	253	125	175	~60	-	-	-	-	-	-	-	-	-
ENTHALPY, BTU/LB	13,033	-	-	-	-	-	22,317	-	-	-	-	-	-	-	-	-
HEAT RATE, MM BTU/HR	4551.84	-	-	-	-	-	75.88	-	-	-	-	-	-	-	-	-
SOLIDS, % WT	95.87	-	-	-	-	-	-	10	-	-	10	25	48	51.3	100	20
DENSITY, LB/CU FT	50	0.0784	0.076	0.0551	0.068	0.0626	0.0465	66.7	62.4	62.4	66.7	74.2	83.7	67.8	60	78.9
SOx, M LB/HR	-	-	-	10.059	1.006	1.006	-	-	-	-	-	-	-	-	-	-
NOx, M LB/HR	-	-	-	2.731	2.7	-	-	-	-	-	-	-	-	-	-	-
PM, M LB/HR	-	-	-	11.964	0.060	0.060	-	-	-	-	-	-	-	-	-	-

a BASIS: 60 HR/WK OPER

Figure 12. Coal-fired power plant, simplified process flow diagram.

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TABLE 32. 500 MWe POWER PLANT DESIGN BASES AND ASSUMPTIONS

Coal Receiving	1000-ton-capacity river barges (175 x 26 ft) (rail hopper cars as alternate)
Onsite Coal Storage	60 days dead, 3 days live
Boiler	Pulverized coal, tangentially fired, balanced draft furnace, controlled circulation drum-type boiler with superheater, economizer and regenerative air preheaters (2650 psig/1000^{o}F)
Steam Generator Cycle	Tandem-compound, quadruple flow, condensing, single reheat turbine (553 MW output capacity, at 1.5 in. Hga exhaust pressure), 2-shell surface condenser, 7 stages of feedwater heating (1 open); 590 MVA/0.95 pf generator, 22kV
Heat Rejection	Mechanical (induced) draft cooling tower, 30^{o} range
Flue Gas Cleanup	Electrostatic precipitator (99% removal efficiency) and line scrubbers (90% SO_2 removal)
Flue Gas Reheat	50^{o}F, direct firing-hot gas mixing (indirect-steam coil heating as alternate)
Solid Waste Disposal	Onsite landfill
Plant Water Supply	River water (pumphouse intake system)
Onsite Water Storage	3-day storage capacity
Plant Load Factor	70% (255 days/yr)
Plant Operating life	30 years

an unbiased sample from the discharge end of the conveyor by reciprocating cutter. The sample is screened, cut further, and portions combined into a 30-pound sample for analysis. Rejects are returned to the coal chute.

Coal can also be received by rail hopper car. An underground hopper is provided for bottom-dump cars. A 42-inch inclined-belt conveyor takes coal from the hopper feeders and discharges it into the transfer house chute.

The inclined stacker feed conveyor runs through the reclaim transfer house (a belt tripper can direct coal to the boiler feed system instead of the stacker) and onto the elevated stacker conveyor. Coal is discharged through telescoping chutes onto one of two conical live storage piles. Three-day live storage is provided. A 60-day dead storage pile lies adjacent. Bulldozers move coal into and out of dead storage as required. Nearly all of the 252,000-ton pile (six acres by 60 feet high) is compacted and sealed to prevent spontaneous combustion and to retard dust blowing.

An under-pile dual reclaim system provides coal to the boiler at a nominal 175 tph. Each parallel system has a 355 tph design capacity (200 percent of nominal usage). In the reclaim tunnel under the live piles, six of the twelve 60 tph vibrating feeders discharge coal onto one of the two 30-inch reclaim belt conveyors. These inclined conveyors emerge from the tunnel and terminate in the transfer (crossover) house. Coal from the divided transfer chute feeds one of two 30-inch-wide belt conveyors taking coal to the boiler cascade distribution system. The cascade system loads the five 300-ton capacity boiler silos to full-level indication in sequence (or specifically individually upon low-level indication). Normally four silos are in use at the 100-percent load conditions. The silos and conveyor discharge points are ducted to a baghouse dust collector (3250 square feet collection area) where a 13,000 cfm fan provides positive air flow.

Combustion Section

A pulverized-coal tangentially-fired balanced-draft boiler takes siloed coal, pulverizes it, and burns it in the presence of 20-percent excess air, releasing about 4552 million Btu per hour in the combustion zone of the water well furnace. Heat is transferred by radiation and convection to the boiler tubes, generating steam. Flue gas exits the boiler through two regenerative air preheaters and passes to the electrostatic precipitators at negative pressure.

Five gravity feeders supply coal from the silos to five 100,000 lb/hr roller mills (four normally in operation). Primary air (blend of preheated air and cold air at 600°F) is fed to the mills from the PA fans and conveys the pulverized coal to a set of 24 burners (at corners on six levels). Ambient air discharged from two forced-draft fans passes through the steam air heaters and the air preheaters and enters the windbox plenum serving the tangential burners and the overfire air ports. A combustion control system regulates coal air rates and combustion temperatures. Natural gas is used for startup. The ignitor windbox houses electric ignitors adjacent to the warmup guns.

Combustion products pass through the boiler section, through the air preheaters, and into the ducting to the precipitators. At full load (100 percent), about 175 tph of coal are burned and about 1.3 MMCFM of flue gas enters the precipitators. Bottom ash is collected in two hoppers below the combustion section. Ash hoppers are also provided for the economizer and the flue gas exit side of the air preheaters. It is assumed that 15 percent of the entering ash is collected in the bottom ash and economizer hoppers. Ash handling is discussed later.

Boiler efficiency is about 89.7 percent (heat input to steam) at 100-percent load and average conditions. Over eight percent of the input heat is lost in the dry gas and the water from the fuel (fuel moisture and water produced from fuel hydrogen).

Flue Gas Cleanup

The flue gas cleanup system is composed of electrostatic precipitators for particulate matter removal (flyash collection) and lime scrubbing for sulfur oxides removal. In addition, sludge stabilization is provided wherein dewatered scrubber sludge, dry flyash, and a cementation agent (lime) are blended to give a stabilized material suitable for landfill disposal.

Flue gas from the air preheaters enters two parallel precipitators, each handling 50 percent of the flow (650,000 ACFM each and two gas paths). Each precipitator is 99 feet wide, 73.5 feet high, and 78 feet deep and contains 233,280 square feet of effective collection area with eight bus sections in the direction of flow. Design particulate removal efficiency is 99 percent. Maximum power capability is 0.04 kW per MCFM.

Collected ash is discharged into the precipitator hoppers by plate rappers operating on a sequential timer control. The bulk of the ash is collected in plate sections near the precipitator inlet faces. Flyash is removed from the hoppers by a pneumatic conveyor system, again by sequential timer control. Cleaned gas leaves the precipitators at 250°F and 15 inches (water column) below atmospheric pressure. Two 5000 hp induced-draft fans boost the flue gas pressure to plus 10 inches (water column) to overcome the pressure drop in the FGD system.

Sulfur dioxide removal is accomplished in the following conceptual design. It is noted that such a system has not yet been operated over an extended period and with the degree of reliability required by the bypass provision. The system consists of three parallel scrubbing trains each handling one-third (378,500 ACFM saturated) of the gas flow. Gas bypass ducting is provided for startup of the boiler. Each scrubber can be taken offline independently with concurrent reduction in boiler load. The absorbers are 32-foot diameter by 100-foot high spray towers capable of 90+ percent removal of inlet SO_2 (about 1000 ppmv). Gas is distributed to the absorber inlet presaturation sections (base of tower) and cooled by sprays of recirculating slurry. Gas proceeds upward through the towers being contacted countercurrently with a series of sprays which absorb SO_2 from the gas phase. The liquid-to-gas ratio is 80 gallons per thousand cubic feet. The wet gas passes through a mist eliminator section for removal of entrained particulate moisture and solids. Saturated exit gas at 125°F from each scrubber is recombined in the outlet ducting and reheated to 175°F before entering the 300-foot high concrete stack. Reheat is accomplished by direct mixing of flue gas with hot combustion gas from a natural gas-fired horizontal combustion unit. Table 33 summarizes the major FGD design parameters.

From the absorber, SO_2-rich slurry falls into the 280,000-gallon absorber delay tank located below the spray tower. Five minutes residence time is provided to complete the reaction of lime with SO_2 forming calcium sulfite and calcium sulfate, which precipitate as solubility limits are exceeded.

TABLE 33. FGD SYSTEM DESIGN PARAMETERS
(90 percent SO_2 removal by lime scrubbing)

No. of Absorber Trains	3
Absorber Type	Spray tower
Superficial Gas Velocity	8.5 feet per second
Total System Pressure Drop	9.5 in. water column
Liquid to Gas Ratio (L/G)	80 gal/MCF
Presaturation Sprays	2 gal/MCF
Mist Eliminator Spray	2 gal/sq ft
$CaO:SO_2$ (Absorbed) Stoichiometric Ratio	1.1
Delay Tank Residence Time	5 minutes
Absorbent Solids Concentration	10 percent
Lime Slurry Makeup Concentration	20 percent
Dewatered Sludge Solids	40 percent
Stack Gas Reheat	50°F

Lime slurry makeup is added to the delay tanks to maintain the desired 1.1 CaO:SO_2 (absorbed) stoichiometric ratio. Six 6150 gpm capacity pumps circulate the 10-percent (solids) slurry to the presaturator and spray tower spray nozzles. A slurry bleed stream from each delay tank is pumped to a surge tank and then fed to a 95-foot diameter thickener.

Another recirculating system (washer tray recycle) is provided to prevent scaling and plugging of the mist eliminator and wash tray section of each tower. A recycle pump supplies water to irrigate the wash tray below the mist eliminators in each tower. Tray water is decanted back to a 15,800-gallon recycle tank. A bleed stream from the recycle pump discharge purges accumulated solids from the system. The three purge streams are sent to a 65-foot diameter clarifier where the solids are settled out. Clarifier overflow is pumped back from an overflow surge tank to the mist eliminator and wash tray spray systems of the three scrubbers. Fresh (filtered) makeup water (255 gpm total) is added to the spray water supply. Underflow slurry from the clarifier is pumped to two thickened slurry surge tanks which also receive underflow from the slurry thickener.

At 90-percent SO_2 removal, approximately 250 tons per day of thickened (23 percent solids) slurry are removed from the absorber trains. This sludge is dewatered, mixed with flyash, and stabilized with lime for landfill disposal. The dewatering and stabilization system operates 40 hours per week. Hence, large (338,000-gallon) surge tanks are provided to store accumulated sludge (three-day capacity total). Three rotary vacuum filters 12 feet in diameter by 22 feet long (830 square feet filter area) dewater the sludge to a minimum 40-percent solids cake. Filtrate is pumped from the receiving tanks to a 338,000-gallon surge tank where accumulated filtrate is worked off continuously by being returned to the absorber recirculating slurry loops. The filter units are enclosed in a separate building. Filter cake is discharged onto an enclosed-belt conveyor which transfers the cake directly to one of two 200-ton-per-hour capacity pug mills for blending with flyash and lime (as a cementation agent). The pug mills are located in the sludge stabilization building.

Flyash is pneumatically conveyed from the precipitator hoppers and the air preheater hoppers to twin 475-ton capacity flyash silos. Each provides three-day storage capacity at design load and assuming 90 percent ascending ash in the boiler. Exhaust conveying air from the silo product separators is passed through a baghouse prior to discharge into the atmosphere. At the bottom of each flyash silo, a volumetric screw feeder meters flyash into a pneumatic conveyor supplying a proportional quantity of flyash to the pug mill for blending with dewatered sludge. Lime is also metered by weigh feeder from a 130-ton capacity silo and transported to the pug mill by belt conveyor. Lime is added for cementation of flyash/sludge at two percent on a dry solids basis (1.4 tons per hour lime). The flyash/scrubber sludge/lime blend from the pug mill is transferred by belt conveyor to twin 150-ton capacity truck load-out bins. About 140 tons per hour of stabilized sludge (51.3 percent solids) are generated for disposal. Two 40-ton capacity end-dump trucks haul sludge to the landfill area 40 hours per week. At about 70 pounds per cubic foot, some 160,000 cubic feet of solids per week are landfilled. Miscellaneous sludges produced intermittently in the plant (filter backwash sludge, basin cleanouts, etc.) are also processed in the dewatering and stabilization system.

About 116 tons per day are utilized in the FGD system for SO_2 removal. This lime along with the lime used in sludge stabilization is delivered to the plant in bulk rail cars. Two 1000-ton capacity lime silos provide about 17 days of storage capacity. The rail cars are unloaded pneumatically (vacuum) and a filter collector (baghouse) collects dust escaping the product separators. The stabilization lime silo is also filled from rail cars. Lime is supplied to the scrubbers as a 20-percent slurry. Dry lime is slaked in a 150-ton-per-day package slaker unit with fresh water used for slaking and vacuum filtrate water used for dilution to the 20-percent concentration. The lime slurry is pumped from the slaker transfer tank to a 74,000-gallon agitated slurry storage tank and thence to a similar slurry surge tank. Each tank holds an eight-hour supply of lime slurry at design lime demand in the absorbers. A slurry feed tank pump supplies lime slurry to the three absorber delay tanks.

The entire FGD system operates continuously with equipment shut down for repair or maintenance only during reduced boiler loads. Normal bypassing of the FGD system is not permitted, so critical equipment is spared. Sulfur dioxide analyzers monitor SO_2 concentrations at the inlet and outlet ducting of the FGD system. NO_x and opacity are also monitored continuously in the stack.

Steam Cycle

The boiler maximum continuous capacity is 3,980,000 lb/hr steam flow at 2675 psia and 1005°F at the superheater outlet. At the 100-percent load condition (shown in Figure 12), steam flow at the turbine throttle (high-pressure section) is about 3.37 million lb/hr at 2411.5 psia and 1000°F. The turbine consists of a single-flow, high-pressure section, a single-flow (reheater flow) intermediate-pressure section, and two double-flow, low-pressure sections connected in tandem. Steam from the high-pressure stages returns to the reheat section of the boiler and reheated steam (1000°F) then flows through the intermediate-pressure stages. The exhaust steam flow is divided and enters the two double-flow low-pressure sections, finally exhausting into the two-shell surface condenser. Steam is withdrawn from seven extraction ports for feedwater heating and for driving the steam turbine driver boiler feed pumps.

The hydrogen-cooled generator produces about 504.3 MW (gross output) of power. Its rated capacity is 590 MVA (3600 rpm, 0.95 power factor, 22 kV). Net output is about 476 MW. An isolated phase bus connects the generator to the main transformer where generator voltage is transformed to 345 kV line voltage for transmission to the utility's grid.

Turbine exhaust steam is condensed at 2.5 inches Hg absolute in a twin shell, two-pass, divided waterbox condenser, also serving the boiler feed pump turbines. Circulating water in the tube side of each shell picks up heat from the steam condensing at 108.7°F. Boiler feedwater makeup is added to the hot well. Condensate accumulates in the interconnected hot wells under each shell and is pumped by motor-driven condensate pumps (three 50-percent capacity) through the gland steam and the air ejector condensers and through three low-pressure closed feedwater heaters. The condensate is deaerated by steam contact in a horizontal-spray tray type deaerator. A deaerated condensate storage tank provides five minutes surge capacity for the booster pumps which pump condensate through two intermediate-pressure feedwater heaters to the boiler feed pumps. The steam-turbine-driven boiler feed pumps supply condensate at about 2900 psia to the high-pressure feedwater heater, and the heated feedwater enters the economizer section of the boiler at about 460°F.

Feedwater flow from the economizer discharges into the upper horizontal steam drum. Four boiler circulating pumps maintain the desired circulating flows to the various inlet headers of the steam generating circuits. Boiler blowdown (0.5 percent) is taken from the water surface in the steam drum to a blowdown flash tank before discharge to a hold tank. An auxiliary gas-fired boiler is provided for startup of the main boiler and also for boiler chemical cleaning. During normal operation, the auxiliary steam supply will be saturated 250 psig steam (pressure reduced) from the main boiler steam drum. Auxiliary steam is used in the plant heating system and in the air ejectors. Steam losses (including soot blowing) total about 14,000 lb/hr.

Auxiliary Systems

Environmentally related auxiliary systems discussed here are the water systems, wastewater treatment, and solids disposal. The following systems are not described: bearing cooling water, lube oil handling, compressed air, sampling, fire protection, heating, ventilating and air conditioning, and electrical.

Water System--

Figure 13 shows a simplified water balance for the plant. Plant makeup water is supplied from the river intake water pumphouse by three 50-percent capacity (2,200 gpm) vertical wet-pit pumps. The intake structure is equipped with trash racks and traveling screens to prevent intake of debris. River water is pumped through a 20-inch diameter pipeline to the onsite water storage basin. The 18.2-million-gallon earthen basin provides a three-day supply of water for the plant. Main fire pumps are also located in this pond. Average plant water demand at the 100-percent load condition is about 4100 gpm.

The circulating water system and service water system provide cooling water to the main condenser and to all of the auxiliary system coolers (service water). Two induced-draft cooling towers reject the waste heat to the atmosphere by evaporative cooling. Each tower is 288 feet long by 71 feet wide by 51.5 feet high and contains eight standard cells each with a 28-foot diameter, 200 hp fan. The total cooling duty at average conditions is about 2350 million Btu/hr with a cooling range of 30°F (72.7°F to 102°F) and an 11.2°F approach to the wet bulb temperature. The circulating water system is maintained at a minimum of 10 and an average of 25 cycles of concentration. At average conditions, evaporation and drift losses total about 3533 gpm.

The 50-percent capacity (90,000 gpm) pumps circulate cool water from the tower basins through a 90-inch diameter line to the surface condenser. Blowdown is taken from the discharge side of the circulating pumps. Service water is

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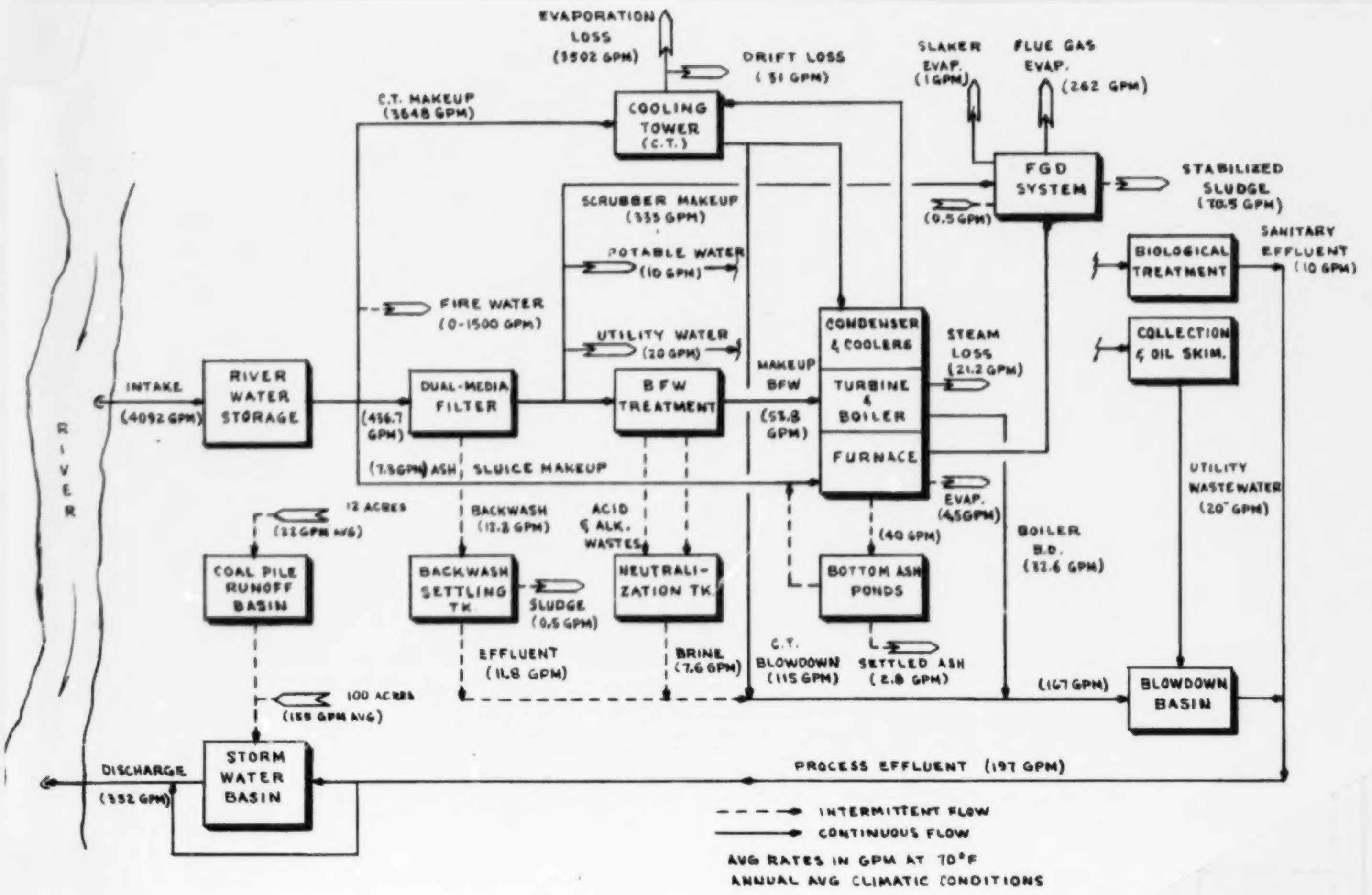
EVAPORATION LOSS (3502 GPM)
DRIFT LOSS (31 GPM)
SLAKER EVAP. (1 GPM)
FLUE GAS EVAP. (262 GPM)
C.T. MAKEUP (3648 GPM)
COOLING TOWER (C.T.)
FGD SYSTEM
STABILIZED SLUDGE (70.5 GPM)
(0.5 GPM)
SCRUBBER MAKEUP (335 GPM)
POTABLE WATER (10 GPM)
SANITARY EFFLUENT (10 GPM)
BIOLOGICAL TREATMENT
FIRE WATER (0-1500 GPM)
UTILITY WATER (20 GPM)
CONDENSER & COOLERS
STEAM LOSS (21.2 GPM)
COLLECTION & OIL SKIM.
TURBINE & BOILER
FURNACE
MAKEUP BFW (53.8 GPM)
INTAKE (4092 GPM)
RIVER WATER STORAGE
(456.7 GPM)
DUAL-MEDIA FILTER
BFW TREATMENT
R I V E R
(7.8 GPM) ASH SLUICE MAKEUP
EVAP. (4.5 GPM)
UTILITY WASTEWATER (20 GPM)
12 ACRES (32 GPM AVG)
BACKWASH (12.3 GPM)
ACID & ALK. WASTES
(40 GPM)
BOILER B.D. (32.6 GPM)
COAL PILE RUNOFF BASIN
BACKWASH SETTLING TK.
SLUDGE (0.5 GPM)
NEUTRALIZATION TK.
BOTTOM ASH PONDS
EFFLUENT (11.8 GPM)
BRINE (7.6 GPM)
C.T. BLOWDOWN (115 GPM)
SETTLED ASH (2.8 GPM)
(167 GPM)
BLOWDOWN BASIN
100 ACRES (155 GPM AVG)
DISCHARGE (352 GPM)
STORM WATER BASIN
PROCESS EFFLUENT (197 GPM)
INTERMITTENT FLOW
CONTINUOUS FLOW
AVG RATES IN GPM AT 70°F
ANNUAL AVG CLIMATIC CONDITIONS

Figure 13. Coal-fired power plant, simplified water balance.

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supplied by two (one spare) 12,000 gpm capacity pumps downstream of the circulating water pumps. Hot circulating water returns to the distributors at the top of the two cooling towers. Makeup is supplied by the pondwater pumps.

Sulfuric acid and a dispersant chemical are added to the circulating water to prevent scale formation and solids deposition on heat transfer surfaces. The circulating water is also chlorinated for 24 minutes, three times per day, to prevent the growth and buildup of fouling microorganisms. Residual chlorine is monitored at the outlets of the condenser.

Except for ash sluicewater makeup, the remainder of the plant makeup is treated for the various uses. A dual-media filtration system (two 500-gpm capacity gravity filters) filters water from a pondwater booster pump. A filtered water clearwell provides about 3½ hours of surge storage at average use rates. Filter backwash water is collected and settled in a tank before discharge of clarified water to waste.

Boiler feedwater makeup is produced in a demineralizer system consisting of two parallel trains, each having a cation exchange unit, an anion exchange unit, and a mixed bed polishing unit. Each train can produce 20 gpm of boiler feedwater, and filtered water is supplied to the trains by two demineralizer feed pumps located in the filtered water clearwell. Average demand is about 61 gpm. A 175,000-gallon tank provides surge storage of demineralized water. The ion exchange beds are regenerated with (diluted) 66^o Be sulfuric acid and 50-percent sodium hydroxide. Hydrazine, ammonium hydroxide, and phosphate are added to the boiler feedwater for oxygen scavenging and water conditioning.

Filtered water is chlorinated and supplied separately to an aboveground water tank for distribution to the potable (domestic) water system. The FGD system makeup and other utility water is supplied to the plant water distribution system by clearwell pumps.

Wastewater Systems--

Major plant wastewater sources are sanitary wastes, cooling tower blowdown, boiler blowdown, confined yard and floor drainage (utility wastewater), demineralizer regenerant wastes (intermittent), filter backwash (intermittent), coal yard, switchyard, and general plant area runoff (intermittent). Equipment cleaning and basin and tank cleaning wastes are infrequent sources of wastewater.

Sanitary wastewater is collected separately and treated in a packaged biological treatment unit which includes biological oxidation, clarification, filtration, and disinfection. Cooling tower blowdown and boiler blowdown streams are collected in a 750,000-gallon concrete basin which provides (at full level) about 2½ days' equalization and suspended solids settling capacity. It also receives utility wastewater from local sumps equipped with oil skimmers. The basin water is monitored for pH, oil and grease, residual chlorine, and suspended solids. This basin is also used for retention and treatment of equipment cleaning wastes. Overflow enters the stormwater settling pond. Demineralizer regeneration brines are collected and neutralized in a tank before discharge to the blowdown basin. Similarly, filter backwash water is collected

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in a tank to allow solids settling and clarified backwash is discharged to the blowdown basin. Backwash sludge is pumped intermittently to the FGD sludge filtration system.

Plant yard areas that have storm drains or drainage ditches total about 112 acres, including the initial five-year sludge landfill site. Coal yard runoff (12 acres drained) is collected separately in a 1.1-million-gallon clay-lined pond which can impound the first 50 percent of the runoff from a 10-year, 24-hour duration storm. Annual runoff (35 inches assumed) from this area would average about 22 gpm as a continuous flow. The coal yard pondwater is monitored for pH and suspended solids. Lime slurry from the FGD lime makeup system can be used to neutralize acidity if needed before discharge to the main stormwater pond. Switchyard runoff passes through an oil separator (corrugated plate interceptor) to collect lighter- and heavier-than-water fluids.

The remainder of the plant area drainage (about 100 acres) is collected in a 7.8-million-gallon settling pond provided for settling out suspended solids picked up by the surface runoff. The sludge disposal landfill area is drained to this pond. About 50 percent of the runoff from a 10-year, 24-hour duration storm can be impounded. At 30 inches of annual runoff, this runoff would average about 155 gpm as a continuous flow. Impounded stormwater could be used as cooling tower makeup during storm periods when river water turbidity is likely to be high. Unimproved portions of the 365-acre plant site have drainage patterns directed away from the main plant drainage system.

Normal plant effluent can be directed through the stormwater basin before discharge to the river, though usually the basin is bypassed. Plant effluent and stormwater flow by gravity through a pipeline to the river discharge diffuser downstream of the intake pumphouse. Effluent is discharged below the water surface through multiple pipe section diffusers on a header pipe.

Ash Handling--

Bottom ash, coal mill rejects, and economizer ash are handled in a recirculating sluice system which deposits the ash in one of three small (one acre) ash ponds. About 2110 lb/hr of ash is collected (15 percent of entering ash). Economizer ash is discharged to the bottom ash hoppers. A low-pressure pump continuously recirculates ash sluicewater from a surge tank near the boiler. The tank receives makeup water (during non-sluicing periods) from the river water pond booster pump. During the sluicing operation (once per day), a high-pressure pump sluices ash from the bottom ash hoppers to the pond. In the same cycle, rejects from the mill reject bins are also sluiced to the ash pond. A recycle pump in the ash pond decant section returns water to the surge tank to maintain the sluicewater supply during the operation. The three one-acre clay-lined ash ponds are rotated in service about every eight or nine months. Each contains a decant section for clarifying sluicewater for recycle. When filled with ash, the pond is taken out of fill service and sluiced ash from the boiler is routed to an empty pond. Decant water continues to be used until a low water level is reached. The ash is then dredged out and hauled by truck to the landfill site. Assuming the dredged ash has a 40-percent moisture content, some 425,000 cubic feet (10,760 tons) would be disposed of per year.

Solid Waste Disposal--

Over six million cubic feet per year of stabilized flyash/FGD sludge is produced along with the bottom ash and a small amount of plant trash and garbage. It is assumed that these materials can be deposited to an average height of 25 feet on fairly level terrain without stability problems occurring and without the need for constructing impoundments or retaining structures. The landfill areas are developed in five-year increments (32-37 acres). The materials are dumped, spread, and compacted in two- to three-foot layers. Soil cover is applied on areas where the final height has been built up. Soil stabilization and revegetation commence when a workable area has been filled and covered.

Other Facilities--

As indicated in Figure 11, plant physical facilities include buildings -- the turbine hall, warehouse and shops, the administration building, the water treatment, filter, and sludge stabilization buildings — roads, rail spur, parking areas, fences, gatehouse, and other site improvements.

Thermal Balance

The overall plant heat rate is about 9563 Btu/kWh at 100-percent load conditions and excluding the heat input (78 MM Btu/hr) for flue gas reheating. Table 34 summarizes major factors in the plant thermal balance. A large portion of the energy input is (lost) dissipated to the atmosphere in the form of enthalpy (added) of cooling-tower exhaust air and water vapor — heat rejected from cooling water.

Auxiliary power losses include about 6.6 MWe consumed by the electrically driven equipment in the FGD system or about 1.3 percent of the gross output. This is about the same amount as the electric power consumed by the PA, FD, and ID fans (6.9 MWe). Net plant output is about 476 MWe or 35.7 percent of the coal heat input.

A 50°F flue gas reheat system has been included to mix hot gas from a natural gas-fired combustion box with the saturated flue gas from the scrubbers. Gas consumption represents about 1.7 percent of additional heat input and lowers the overall plant thermal efficiency to about 35.1 percent (total input basis). Other reheat options would be indirect steam coil heating of outside air to mix with the cold flue gas or direct steam coil heating of the flue gas. Both options would use steam either from the auxiliary boiler or from the main steam system. Both options would be somewhat less efficient than the simple system chosen for illustration.

TABLE 34. COAL TO POWER THERMAL BALANCE ELEMENTS

	MM Btu/Hr	kW	% of Input
Coal Fuel Input	4,551.8	1,333,670	100.0*
(-) Furance Losses at 10.3%	(468.8)	(137,730)	(10.3)
= Input to Steam	4,083.0	1,196,300	89.7
(-) Steam Cycle Losses	(2,332.0)	(683,280)	(51.2)
= Output at Turbine Exhaust	1,750.9	513,020	38.5
(-) Turbine Generator losses at 1.7%	(29.7)	(8,720)	(0.7)
= Gross Plant Output	1,721.2	504,300	37.8
(-) Auxiliary Power Losses	(96.6)	(29,300)	(2.1)
= Net Plant Output (9563 Btu/kWh)	1,624.6	476,000	35.7

*Gas fuel input to reheat flue gas excluded — this adds to input: 78.2 MM Btu/hr, 2290 kW, 1.72% of coal heat input.

COAL-TO-POWER PLANT COSTS

Capital and annual operating cost summaries for the 500 MWe conceptual plant are given in Tables 35 and 36. Appendix C discusses the cost estimation basis and methodology. The $384 million total capital cost represents about $800/kW (net). Major pollution control equipment is estimated at $20 million or about 10 percent of the direct field cost. The electrostatic precipitators and the FGD system constitute the bulk of this installed equipment cost. On a total capital cost basis, the pollution control portion would be roughly $85/kW (net) or 10 percent. A considerable part of the startup costs could be attributed to the FGD system. Excluded are all costs associated with preparing an environmental impact report, obtaining environmental permits, and obtaining any emission offsets that may be required. Distribution costs are also excluded.

TABLE 35. COAL-TO POWER CAPITAL COSTS

Element	$1,000,000's
Site and Yard	9.5
Civil/Structural	23.0
Process Mechanical Equipment	97.0
Pollution Control Equipment	20.2
Piping and Instrumentation	22.8
Electrical	19.8
DIRECT FIELD COST	192.3
Indirect Field Cost	22.4
TOTAL FIELD COST	214.7
Engineering Services	25.7
	240.4
Allowance for Uncertainty	48.1
TOTAL CONSTRUCTION COST	288.5
Land	0.7
Other Owner Costs	14.4
Startup	14.4
Allowance for Funds During Construction	47.7
FIXED CAPITAL INVESTMENT	365.7
Working Capital	18.3
TOTAL CAPITAL COST First Quarter 1978, Price and Wage Levels	384.0

TABLE 36. ANNUAL OPERATING AND MAINTENANCE COSTS* — COAL TO POWER

Element	$1,000,000's
Supplies	2.0
Utilities	1.2
Operating Personnel	0.7
Maintenance Labor and Materials	2.0
Supervision	0.3
Administration and Overhead	0.9
Local Taxes and Insurance	7.7
TOTAL ESTIMATED ANNUAL OPERATING COST First Quarter 1978, Price and Wage Levels	14.8

*Excluding coal feedtock.

The annual operating cost, excluding coal, of $14.8 million represents about five mills/kWh (net). No estimate was made of the pollution control portion. Certainly, lime for the FGD system is a major fraction of the chemicals cost (supplied). Disposal of the stabilized FGD sludge was assumed to be rather straightforward with no particular handling or environmental hazard difficulties. Sludge disposal would be considerably more expensive were the material designated as a hazardous waste.

Figure 14 shows the effect of delivered coal costs on the cost of electricity for private and utility financing. At, say, $25/ton in this region, the fuel cost is about one-third of the 20 mills/kWh cost of electricity.

COAL-TO-POWER ENVIRONMENTAL ASSESSMENT

Feedstock procurement impacts and impacts of the operating plant are described in the context of a hypothetical South Central U.S. site.

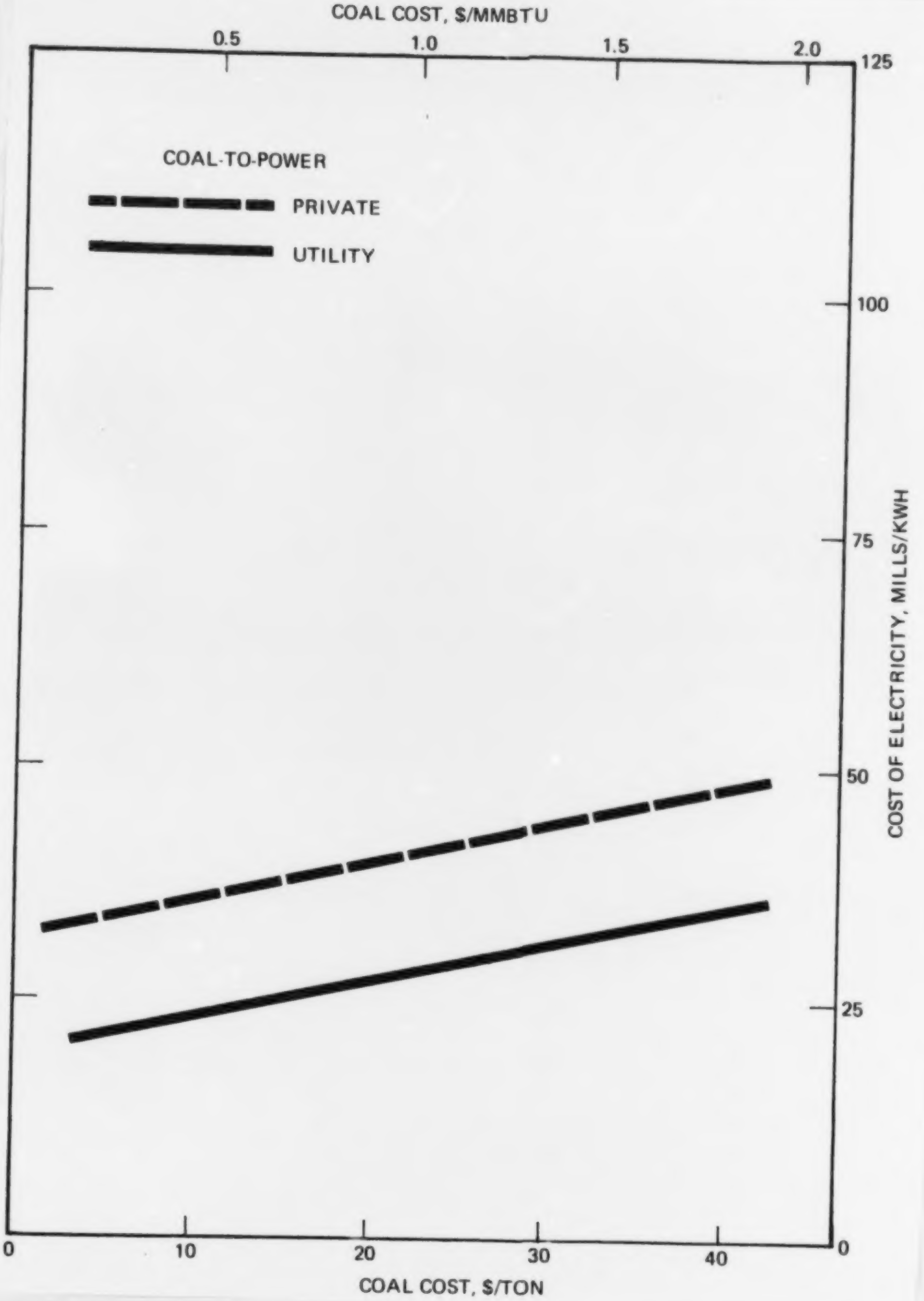

Figure 14. Effect of coal cost on cost of electricity with both private and utility financing.

Coal Procurement Impacts

About one million tons per year of coal will be required from strip mines in the area proposed as the source of coal for the plant. Impacts on land, water, air, and biology will be typical of strip mines regardless of location, although site-specific characteristics may modify the significance of the impacts. The impacts are summarized in Table 37.

Topography--

The normally hilly terrain will be disrupted at the mine site, with from zero to 100 feet of overburden removed (excavated) and stockpiled prior to coal removal. Land reclamation will result in an approximation of the original topography, but it is likely that elevations of hills will be lower by at least the amount of coal and other materials removed; that normal topographical irregularities will be replaced with a more regular, rolling terrain; and that the contours of the mined area will not be exactly as the original contours. However, given past uses of the area and the likely continued use for strip mining, these topographical changes will not be unusual. Therefore, the direct impact of strip mining on topography will be marked, but not significant to the regional topography.

Soils and Geology--

Removal of the required million tons of coal per year will result in three direct changes in regional soils and geology:

- Disruption of the natural geologic structure and the physical properties of the overburden by destroying the original stratification of beds, geologic structures, and natural strength

- Removal and consumption of the coal, a nonrenewable resource

- Intermixing of soil horizons, possibly bringing to the surface materials that may be harmful to plant growth

Stockpiling of soils and subsoils may also result indirectly in "bulking," or an increase in volume, of the overburden, with the result that, upon reclamation, the fill would be less dense and subject to compaction and settling over time. In addition, stockpiling of topsoil may result in lowered productivity of the soil since the stockpile will become biologically sterile with time. Upon reclamation, productivity cannot be restored until the area has been biologically reinoculated and the normal bacteriological and mycological populations have been restored.

Groundwater--

Possible impacts on groundwater (depending on aquifer structure at the mine site and the location of recharge areas) are:

- Removal of existing shallow aquifers or portions thereof, and replacement by unstructured overburden or spoil

TABLE 37. PROCUREMENT IMPACT SUMMARY — COAL

Environmental Factors	Coal Mining Impacts	Mitigating Measures
Topography	Minor changes in land form after reclamation	Mine-site reclamation to simulate existing topography
Soils and Geology	Possible settling and compaction of reclaimed area; reduced soil productivity; consumption of nonrenewable resource (coal)	
Groundwater Quality	Possible interruption or loss of aquifers (shallow) and recharge areas as well as related change in groundwater quality	
Surface Water	Alteration of drainage patterns, flows; increased erosion and siltation in streams; losses of some tributaries	Mine-site controls on drainage; reclamation to restore drainage pattern if possible
Air Quality	Increased particulate emissions-fugitive dust	
Vegetation and Wildlife	Removal of mature woodlands and associated animals; potentially significant local impact on endangered red cockaded woodpecker	Revegetation plans, wildlife management incorporated into reclamation of mine site
Land Use	Short-term commitment to mining; potential long-term reduction in productivity; altered uses resulting	Reclamation of mine site
Aesthetics	Sharp visual contrast but not significant given surrounding land uses; short-term	Reclamation

(Continued)

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TABLE 37. (Continued)

Environmental Factors	Coal Mining Impacts	Mitigating Measures
Community Economy	Potential for increased employment, personal and regional income	
Community Population and Services	Small population increase possible with equivalent increase in demand for goods and services	
Labor Availability	Local labor pool adequate	Training programs to be initiated
Transportation	Mine-site roads required — no discernable effect; local congestion may occur on haul roads between mine site and plant at times	

- Reversal of recharge/discharge relationships by interfacing with recharge areas and/or draining aquifers (dewatering) during the mining operation

- Altering groundwater quality by changing the sources of chemicals in the water (rock and biosphere); by changing hydraulic, thermal, and chemical gradients; and by losses of precipitation, ion exchange, sorption, and biosphere effects on the groundwater

The effect, whether permanent or temporary, cannot be predicted without studies of mine-site groundwater. However, while changes in groundwater availability and quality are likely and will be adverse, their regional significance will depend on present groundwater problems as a result of mining, regional dependence upon groundwater as a potable water supply, and future needs which might require protection of all potential water supplies.

Surface Water--
Changes in topography will result in changes in drainage, possibly altering the quantity and quality of water downstream of the mine. Strip mining and overburden stockpiles near rivers or streams can result in erosion, increased turbidity, and siltation. In addition, physical barriers to runoff, including removal of streams and small watersheds, can affect river flows locally. Uses of erosion control methods and reclamation of the mine site as mining progresses (rather than long-term stockpiling) will reduce the long-term significance of these effects. The present mining use has probably already affected surface

waters and, if care is taken in expansion of the mining operation, additional impacts on surface water can be kept to a minimum.

Air Quality--
Removal of vegetation and disruption of topsoil will contribute to increased particulate emissions in the form of fugitive dust. The quantity in tons per year will depend on the area disturbed (dependent on richness of the coal vein and the timing of reclamation) as well as the average wind speed in the area. Most emissions produced will likely be extensions of present air quality problems attributable to mining in the area.

Vegetation--
An unknown quantity of longleaf pine, slash pine, and loblolly-shortleaf pine vegetation will be removed in the course of mining. The exact acreage will depend on the richness of the coal vein and therefore upon the quantity of surface area to be disturbed for economic removal of the required quantity of coal. While this acreage may not be significant to the regional ecology (which is predominantly loblolly-shortleaf pine), the local impact will be significant and long-term. Standardized reclamation procedures, with specified pine, grass, and legume species, will reduce the impact over the long term, but the quality of habitat produced may not be equivalent to the present vegetation. This may be particularly true if soil productivity is reduced, if altered topography affects plant growth, or if the specified plant species for revegetation do not allow a community to develop which is equivalent in variety to the present pine flatwoods.

Wildlife--
A major potential effect would be the loss of mature pine flatwoods which are the preferred habitat of the red cockaded woodpecker, an endangered species which requires stumps or dead stubs of trees found only in a mature woodland. Since strip mining could result in a major long-term loss of mature woodland, this endangered species could be seriously affected in the mining region.

In addition, the normal wildlife populations in the removed vegetation types will be displaced or removed when the vegetation is removed. In both instances, increases in mortality of local species will result. Nearby populations will be available to repopulate revegetated habitat should the area be able to support these animals. Some species, such as raptors, may benefit since more open grassy fields will probably support larger populations of prey species (e.g., rodents) than pine flatwoods. However, decades may be required for restoration of habitat for species dependent on mature woodlands.

Land Use--
Careful planning of mine-site reclamation keyed to simulate or even enhance alternative land use (i.e., recreational plans, wildlife management, soil enhancement for agriculture, woodlot planting) may benefit future uses of the area. Present uses of the land surface will be preempted during mining, and some uses may be restricted after revegetation.

- Overburden compaction and settling may restrict building on the reclaimed site

- Altered soils may temporarily reduce the value of the area to agriculture or grazing

- Economically important woodlands (lumber, pulp) may not be available for many years following revegetation

- Present recreational uses (hunting) will be eliminated during mining and may not be appropriate in the reclaimed areas

Since present land use includes surface mining, these changes may not be inconsistent with projected land use of local plans and zoning.

Aesthetics--
Constrasts in color (variations in soil color, exposed coal beds, and subsoils), land forms (open pits, service roads cut into hillsides, unshaped stockpiles of overburden, and topsoil), and texture (bare soil-vegetation) will make the mine site aesthetically displeasing. The overall effect, however, will be in keeping with the present appearance of the area due to present mining activities, and reclamation activities will further moderate the impact.

Social and Economic Effects--
The major socioeconomic impacts generated by strip mining include:

- Increases in population and employment associated with expanded mining efforts

- Increases in regional and personal incomes as a result of expansion of mine-related employment and the sale of coal

- Increased demand for goods and services proportional to population increases but offset at least partially by increased incomes

The degree of impact cannot be determined without complete data on the expansion of mining effort required. However, given past production in the region of nine million tons per year, and a requirement by this project of one million tons per year, it might be reasonable to assume an employment increase of a maximum of one-ninth the present workforce and resultant income proportional to this maximum increase. Most of the new employees will probably be hired from the local labor pool (skilled and unskilled), but some population increase may also result. Net socioeconomic impacts are likely to be beneficial.

Plant Impacts

Impacts of the coal-fired power plant on the environment will occur during plant construction and during the operating life of the facility. Construction activities will cause primarily short-term impacts except for the direct alteration of the land surface. Operation impacts are longer-term in nature and result primarily from air, water, solid waste, and noise emissions from the operating plant. In addition, the plant will consume resources that will then not be available for alternative uses. Table 38 summarizes principal resource requirements (on an annual consumption basis) and consumption versus product output (power). The land requirement includes about 230 acres for land disposal of solid wastes over the plant operating life. Table 39 lists approximate chemical consumptions.

Plant impacts are broken down into physical/chemical, biological, aesthetic, and socioeconomic categories for discussion.

Physical/Chemical Emissions and Impacts--
Physical/chemical emissions will occur during both the construction and operation stages. Estimates of air, water, and solid waste emissions are summarized for the operating plant and general impacts described.

Air Emissions--The major point-source emissions to the atmosphere will be the boiler stack gas and the exhaust from the two cooling towers. Material handling

TABLE 38. PRINCIPAL RESOURCES COMMITTED TO PLANT OPERATION — COAL TO POWER

Resource Category	Quantity	Normalized Quantity (Output)*
Land	365 acres	0.77 acre/MWe**
Coal (13,033 Btu/lb)	1,068,720 tons/yr	0.734 lb/kWh (9,563 Btu/kWh)
Natural Gas (1,024 Btu/cu ft)	470 MM cu ft/yr	165.2 Btu/kWh
Diesel and Gasoline Fuel	89,000 gal/yr	4.1 Btu/kWh
Auxiliary Power	173.2 MM kWh/yr	0.06 kW/kW
Water	1,500 MM gal/yr	0.51 gal/kWh
Chemicals	32,200 tons/yr	0.022 lb/kWh
Manpower (95 employees)	190,000 manhours/yr	0.2 men/MWe

*Basis 2913.12 MM kWh/yr net output.
**1.54 acre/MWe if 365 acre buffer zone is included.

TABLE 39. SUMMARY OF ANNUAL CHEMICALS CONSUMED — COAL TO POWER

Chemical	Amount Per Year
Lime (90% CaO)	31,800 tons
Sulfuric Acid (66% Be)	139 tons
Caustic Soda (50%)	33 tons
Chlorine (Gaseous)	61 tons
Hypochlorite (10%)	3 tons
Trisodium Phosphate	6 tons
Hydrazine (35%)	26 tons
Ammonium Hydroxide (29.4%)	8 tons
Dispersant (Proprietary)	12 tons
Polymer	1 ton
Boiler Cleaning Chemicals (Citric Acid, Soda Ash)	60 tons
Dust Suppression Chemicals	1,500 gal
Ion Exchange Resins (3-Year Life)	45 cu ft
Lube Oil	10,000 gal

operations will be a source of fugitive dust emissions, primarily coal dust. Table 40 lists anticipated source and estimates of pollutant emissions.

A variety of dust control techniques will be used to limit fugitive emissions from point and area sources. Coal will largely be handled in enclosed conveyors, discharging into bins or chutes equipped with ducting to fabric filter (baghouse) collectors. Wet chemical suppression (sprays) will be used at the barge unloading station, at the feeders in the reclaim tunnel, and as needed on the coal storage piles. As indicated in Table 40, windblown dust emissions at the barge dock and at the live storage pile are expected to be significant at times. Coal-dust particles will be deposited in the river around the barge dock during unloading. Telescope chutes on the stackers at the live storage piles will discharge coal at the surface of the conical piles. This will help to reduce the exposure of falling coal to the wind. In addition, the piles will be sprayed periodically with chemical dust supressants to retard windblown losses. The dead storage pile will be compacted and treated with a crusting agent.

Outside live storage piles could be replaced by enclosed storage (large concrete silos) to reduce windblown dust emissions. Enclosed storage is not a common practice, however.

The boiler stack gas discharge is expected to comply with the proposed NSPS for particulate matter, opacity, sulfur oxides, and nitrogen oxides. The flue gas cleanup train of electrostatic precipitators and wet lime scrubbers will remove more than 99 percent of the uncontrolled particulate emissions and 90 percent of the uncontrolled sulfur oxide (SO_x) emissions. A small fraction of the nitrogen oxides (NO_x) may also be captured by the wet scrubbing system. About 12 tons per day of SO_x and 32 tons per day of NO_x will be discharged to the atmosphere from the 300-foot high stack. It is anticipated that the 0.6 lb NO_x/million Btu heat input standard can be met with good combustion control. Lesser quantities of carbon monoxide and unburnt hydrocarbons also will be emitted.

About 130 MW of thermal power will be emitted from the stack — somewhat less than 10 percent of the total plant heat input. Combustion of coal at high flame temperatures (2300-3000°F) may liberate some trace elements as vapors and may also form carcinogenic organics. High boiling species (nonvolatiles) will generally be retained in the bottom ash (slag) and flyash. Intermediate boiling elements (antimony, arsenic, cadmium) may vaporize and then condense on particulate matter as the flue gas is cooled. Low boiling elements (mercury, fluorine, and chlorine) may occur primarily as vapors, but are unlikely to pass completely through the flue gas cleanup train. Nevertheless, some small quantities will be emitted, either in vapor form or associated with particulate matter.

The two cooling towers will discharge about 690 MW of thermal power (2350 MM Btu/hr) to the atmosphere and will evaporate nearly 876,000 lb/hr of water under average conditions. Although heat and water vapor are not normally considered air pollutants, their release will have a small localized adverse effect; water vapor condensing in the plumes may increase local fogging. A natural draft tower could be used, if necessary, to reduce the incidence of ground level fogging.

TABLE 40. SUMMARY OF ESTIMATED AIR EMISSIONS — COAL TO POWER

Emission Source	Flow Quantity	Pollutants	Emission Rate
Coal barge Unloading	1000 tph, 5000 tons in 8 hr	Fugitive coal dust	500 lb/day (after wet supression)
Transfer and Sample House	100 tph, 5000 tons in 8 hr (4 x MMCFD vent air)	Fugitive coal dust	12 lb/day (0.02gr/CF after collector)
Coal Stackers (Live Piles)	1000 tph, 5000 tons in 8 hr	Fugitive coal dust	500 lb/day (telescopic chutes)
Coal Storage Piles	12,600 tons live, 252,000 tons dead storage	Fugitive coal dust	250 lb/day (wet chemical supression)
Reclaim Transfer House	175 tph, (3.6 MMCFD vent air)	Fugitive coal dust	10 lb/day (0.02gr/CF after collector)
Boiler Cascade System	175 tph (avg) (3.6 MMCFD vent air)	Fugitive coal dust	10 lb/day (0.02gr/CF after collector)
Lime Storage Silos	125 tpd lime (avg) (0.4 MMCFD conveying air)	Fugitive lime dust	6 lb/day (0.1gr/CF after collector)
Flyash Storage Silos	143 tpd ash (1.6 MMCFD conveying air)	Fugitive dust	23 lb/day (0.1gr/CF after collector)
Solid Waste Disposal Area	1123 tons placed in 8 hr, 3 to 5 acres exposed surface (avg)	Fugitive dust	100 lb/day (wet chemical suppression)
Miscellaneous Sources	Plant area and roads	Fugitive dust	small
	Mobile equipment exhausts	Combustion Products	small
	Fuel storage tanks	Hydrocarbon vapors	small

(Continued)

TABLE 40. (Continued)

Emission Source	Flow Quantity	Pollutants	Emission Rate
Boiler Stack (300 ft high)	4,704,960 lb/hr* (1,253,310 CFM) flue gas and reheat gas	Particulate matter	60 lb/hr (0.013 lb/MMBtu)
		SO_x	1,006 lb/hr (0.22 lb/MMBtu)
		NO_x	2,700 lb/hr (0.6 lb/MMBtu)**
		CO	228 lb/hr (.05 lb/MMBtu)**
		HC	91 lb/hr (.02 lb/MMBtu)**
		Thermal	454 MMBtu/hr
Cooling Tower	84.9 MMlb/hr dry air (18.5 MMSCFM)	Water droplets (drift)	15,670 lb/hr
		Salts (in drift)	40 lb/hr
		Thermal (added to air)	2350 MMBtu/hr

*Hot flue gas will contain trace quantities of volatile heavy metals present in coal feed; most of the metal constituents are retained in the bottom and flyash or condense on the ascending particulate matter (ash)

**Assumed emission factors

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In addition, about 190 tons per day of water in droplet form (drift loss) will be emitted from the towers. Some 120 tons of salts (as TDS in the water droplets) in the drift will be released annually. Most of these salts will be deposited on the ground in the vicinity of the towers. This deposition of salts over time could result in buildup of salts in the soil and/or in indirect adverse impacts on vegetation.

The overall impact of particulate matter, SO_x, NO_x, CO, and hydrocarbon emissions to the atmosphere will be a small degradation of ambient air quality in the vicinity of the plant. The tall stack will help to disperse the pollutants. The emissions of unburnt hydrocarbons will probably exceed 100 tons per year. Since the hypothetical site is a nonattainment area for photochemical oxidants, an emission offset may be required. It is unlikely that primary air standards for other pollutants will be exceeded as a result of emissions from this plant.

Water Emissions--Plant wastewater will be discharged to the river downstream form the intake pumphouse. Figure 10 presented a simplified water balance for the plant. Process effluent will normally be less than about 200 gpm and will contain dissolved and suspended pollutants, most of which are present in the river water at lower concentrations (see Table 18). The plant water treatment system will remove constituents from the river water as dissolved solids, and various chemicals will be added for water conditioning. These, for the most part, will appear in the wastewater effluents. The boiler steam system and the cooling water circuits will act as concentration systems; constituents in the makeup water will appear at concentrated levels in the blowdown streams. The FGD system and the bottom ash sluice system will normally produce no aqueous effluents. Estimated pollutant emissions after effluent treatment are given in Table 41 and are approximate values.

The steam system will have two effluent sources, a blowdown stream to maintain steam purity and the intermittent wastes from ion exchange regeneration. Steam drum blowdown will be fairly clean and somewhat alkaline. Ammonia, hydrazine (N_2H_4), and phosphate additives will appear in the blowdown, but N_2H_4 decomposes into N_2 and H_2O so it should not pose a problem. Suspended solids will be primarily calcium and magnesium sludges that are settled out in the blowdown basin. Trace quantities of iron and copper may be present as corrosion products. Regenerant brines and rinse waters will contain anions and cations removed from the river water by the ion exchange resins plus sodium and sulfate ions from the acid and caustic used in regeneration. The combined wastes after neutralization and settling will have a high dissolved solids content. The relatively high organic and iron content of the river water may make it prudent to include additional water treatment — for example, activated carbon beds — to protect the ion exchange resins.

Cooling tower blowdown at 25 cycles of concentration will contain high concentrations of river water constituents plus sulfate (from sulfuric acid), organic-phosphate dispersant, and chloride from chlorination of the circulating water thrice daily. It is assumed that no metal-based corrosion inhibitor will be used in the circulating water systems, but the exchanger surface in the service water system may need protection. If so, a nontoxic organic inhibitor would be added to the circulating water (and a discharge permit variance requested).

TABLE 41. SUMMARY OF ESTIMATED WASTEWATER EMISSIONS — COAL TO POWER

Source	Estimated Flow	Pollutants	Emission Rate
Boiler Blowdown* (after settling)	32.6 gpm	NH_3 (2 mg/l)	1 lb/day
		TDS (90 mg/l)	35 lb/day
		TSS (25 mg/l)	10 lb/day
		pH (alkalinity neutralized)	8-9 units
Regenerent Wastes** (after neutralization and settling)	7.6 gpm avg. (intermittent)	TDS (2970 mg/l)	270 lb/day
		TSS (25 mg/l)	2 lb/day
		pH (acidity/alkal-neutralized)	6-8 units
Cooling Tower Blowdown† (after settling)	115 gpm (25 cycles of concentration)	TDS (2610 mg/l)	3600 lb/day
		TSS (30 mg/l)	41 lb/day
		Chlorine (residual <0.1 mg/l)	0.1 lb/day
		Dispersant-proprietary (40 mg/l)	55 lb/day
		pH	6-7 units
Sanitary Waste (after treatment)	10 gpm	BOD (25 mg/l)	3 lb/day
		TSS (10 mg/l)	1 lb/day
		Coliforms (<200 MPN/100 ml)	—
		pH	6-9 units
Filter Backwash (after clarification)	11.8 gpm avg. (intermittent)	TSS (50 mg/l)	7 lb/day
		pH	6-7 units
Floor and Confined Yard Drains (after oil skimming)	20 gpm	Oil and grease (10 mg/l)	2 lb/day
		TSS (30 mg/l)	7 lb/day
		pH	6-9 units
Coal Yard Storm Drainage (after neutralization and settling)	22 gpm annual avg. (intermittent flow from 12 acres)	Oil and grease (<10 mg/l)	<3 lb/day
		TSS (<50 mg/l)	<13 lb/day
		Iron, total (<5 mg/l)	<1.3 lb/day
		pH (acidity neutralized)	6-9 units

(Continued)

TABLE 41. (Continued)

Source	Estimated Flow	Pollutants	Emission Rate
Plant Storm Drainage (after settling)	155 gpm annual avg. (intermittent flow from 100 acres)	Oil and grease (<10 mg/l) TSS (<50 mg/l) pH	<19 lb/day <93 lb/day 6-9 units
Chemical Cleaning Wastes (periodic equipment cleaning)	1-2 million gallons per year (infrequent batch discharge)	Acidity/alkalinity, boiler scale, corrosion products, soot — suspended and dissolved solids	Wastes impounded, neutralized, and settled before discharge — TSS <30 mg/l, oil and grease <15 mg/l, iron <1 mg/l, copper <1 mg/l, pH 6 to 9
Basin Cleanouts	Drained basin water and cleaning water volume not estimated	Accumulated solids and sludges	Wastes settled before discharge — TSS <30 mg/l, oil and grease <15 mg/l, pH 6 to 9
Ash Pond Overflow	Normally no flow	Alkalinity, suspended solids, possibly heavy metals and iron	None, unless emergency

*Boiler conditioning chemicals added increase TDS of blowdown.

**NaOH and H_2SO_4 regenerants add to TDS of wastes.

†River water constituent concentrations increase through concentrating effect of the system; H_2SO_4, dispersant and chlorine chemical additions add TDS to blowdown.

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Trace quantities of corrosion products may also be present in the blowdown. The blowdown basin will provide more than adequate holdup for the decay of residual chlorine.

Treated sanitary effluent will be a low-emission-rate source of BOD and suspended solids. Utility wastewater collected from floor and confined yard drains will probably contain washdown solids and some lube oil from leaks and occasional spills. Sump skimmers will be provided to remove floating oil.

Most of the yard and roof drainage will be collected by storm sewers and ditches and should be relatively uncontaminated after settling. On an annual basis, the runoff flow will be large, and significant quantities of suspendible materials washed from plant surface areas could be discharged were a settling basin not provided.

The exposed surfaces of the sludge landfill area will be a potential source of pollutants that may leach from stabilized sludge and bottom ash. It is difficult to assess whether significant amounts of heavy metals could be leached by intermittent contact with direct rainfall, but, in a properly managed landfill, these leachates should not reach groundwater or surface water supplies.

Coal yard runoff will contain dust and may also be acidic if pyrite oxidation occurs from air and water contact with exposed coal surface. Trace metals and some salts may also be leached. The extent of contamination is difficult to predict because of the many factors involved. In this conceptual plant, the runoff would be impounded for settling. If the drainage were acidic, lime slurry from the FGD system could be used for neutralization.

Chemical cleaning wastes generally represent a troublesome problem in power plants. Equipment cleaning is infrequent, but large volumes of waste need to be handled. In this hypothetical plant, impoundment, chemical addition for metal hydroxide precipitation, and settling will be used in batch treatment of cleaning wastes. Effluent discharged will still be high in TDS because of the salts contributed by the cleaning chemicals. Waters from basin elements will be another infrequent source of pollutant discharge. No estimates of the quantities of pollutants discharged were made.

Pollutants contained in the process effluent and in storm runoff are unlikely to cause a detectable change in the river water quality outside of the mixing zone. During heavy rainfall periods, storm discharges may contribute significant quantities of suspended solids to the river, but the turbidity of the river water is likely to be high because of large contributions from natural drainage flows. Surface water withdrawal of about 4100 gpm is only a small fraction of the river flow. The impact on surface water availability would be small.

Solid Wastes--Other than plant trash and garbage, the solid wastes generated routinely in the plant will be collected bottom ash, flyash, and the FGD sludge. Table 42 indicates estimated quantities and disposition, which total about 150 acre-feet per year. A total landfill requirement of 230 acres will be committed for the life of the plant. Properly managed, no other impacts on the physical (water quality) or biological environments should occur from solid waste disposal. The stabilized sludge engineering and physical properties are

TABLE 42. SOLID WASTE DISPOSAL SUMMARY — COAL TO POWER

Source	Estimated Quantity	Potential Pollutants	Disposal
Stabilized Sludge from FGD System and Precipitators	1122.4 tons per 8-hr day, 5 days per week (160,800 cu ft/week)	Alkalinity, trace metals, suspended solids	Sludge* hauled to landfill, spread and compacted, later covered with soil
Bottom Ash Dredged from Ponds	10,765 tons per year (425,340 cu ft) 40 percent moisture	Alkalinity, trace metals, suspended solids	Bottom ash hauled to landfill 1 to 2 times per year, mixed and spread with stabilized sludge, compacted and later covered with soil
Plant Trash and Garbage	475 lb/day general rubbish (~60 cu ft/day compacted)	Decomposable waste, some oily materials	Collected twice per week and buried under stabilized sludge in landfill
Miscellaneous Basin Cleanout Sludges	Infrequent dredging of basins — assume 300 tons per year	Various solids accumulated in basins — some organics and precipitated metals, mostly inorganics	Sludges hauled to landfill mixed with stabilized sludge

*Approximate sludge composition: $CaSO_3 \cdot \frac{1}{2}H_2O$, $CaSO_4 \cdot 2H_2O$, $CaCO_3$, inerts - 32.5%, free water - 48.7%, flyash - 17.8%, lime (cementation agent) - 1.0%.

uncertain. It was assumed that the material was capable of being used as a construction material and that leaching of trace hazardous elements would not be a serious problem. A more elaborate and expensive disposal technique could be needed if the material were classified as a hazardous waste.

Soils and Geology--Approximately 365 acres of land will be altered during construction and operation of the plant. Earthwork will involve clearing, grading, cut-and-fill, and excavation (for settling basins or ponds, landfills, and foundations of structures). The construction of buildings and roadways will further change the physical character of the surface. Site topography, drainage patterns, and soils will be permanently altered during construction. Burial of solid wastes will increase the height of the 230-acre landfill over the plant operating life, further contributing to the long-term changes in topography.

Although the physical changes in soils and geology constitute a local adverse impact, care in selecting a site with no uniquely distinguishing features should minimize the regional impact. However, the extent of topographical change may result in a moderate regional effect, given the present agricultural value of the area.

Biological Impacts--
Construction of the plant will affect approximately 365 acres of biological and agricultural land uses. As a result of earthwork, the vegetation and wildlife associated with the acreage will be removed or disturbed and nearby habitats may be disrupted by increased noise, human activity, and vehicle traffic. Sensitive species will leave the area; others may adapt and remain during the construction phase. However, displacement of wildlife will probably result in locally increased mortality during the beginning of construction, particularly of species which are strongly territorial and/or which are at carrying capacity.

Fencing will present a barrier to movement of larger animals such as deer, but this barrier should not pose a significant problem to most wildlife. Careful siting would avoid disturbance of critical or unique biological habitats, rare or endangered species of vegetation or wildlife, or any economically or recreationally important species.

Secondary biological impacts would include construction-related effects such as plant damage from increased dust on site and at roadsides, increased losses of vegetation from onsite erosion, and stress in aquatic systems resulting from changes in drainage, increased runoff, and turbidity and stream sedimentation. Proper construction management, such as the use of cofferdams and holding ponds on site and dust control, will minimize these impacts.

Air and water quality degradation from plant emissions can affect biota onsite and nearby. While the emissions themselves will not have direct effects on biota, long-term or chronic exposure downwind or downstream could result in cumulative damage. For example, long-term exposure to low levels of NO_X or buildup of salts in the soil downwind of the cooling tower could result in plant damage. Similarly, buildup in the sediments or in the biota (through biomagnification) of toxic materials in the river downstream from the wastewater discharge could result in a loss of some species of aquatic life in an area near the mixing zone.

Small aquatic organisms, such as plankton and fish eggs or larvae, could be entrained in the plant's makeup water system; most would be destroyed either in water treatment or in the plant itself. However, this impact should not be significant if the intake is not placed in a fish spawning ground and if flows and intake screens are designed to minimize entrainment.

In summary, with careful siting and design, biological impacts should be localized, with little impact on regional ecology.

Aesthetic Impacts--

The coal-fired power plant will contrast visually with the surroundings. The plant buildings, stack (300 feet high), induced-draft cooling towers (51 feet high), coal handling facilities, and solid waste collection and disposal facilities will impart an industrial atmosphere to the area, now predominantly agricultural. While these facilities can be masked to some extent by landscaping, use of a buffer zone around the plant site, and plant layout and design, this change in land use constitutes a moderate adverse aesthetic impact.

Social and Economic Effects--

Capital investment in the plant ($384 million) and annual operating expenditures will stimulate the local economy. Temporary jobs will be created for about a thousand construction workers, stimulating the local construction industry. In addition, about 95 permanent operating jobs will be created. Income from these jobs will probably be spent in nearby towns, as will some portion of capital expenditures for equipment and materials. The plant will also expand the local tax base, offsetting at least in part the increased demand for community services.

Plant operating labor and most of the construction workforce can probably be obtained from the regional labor pool, if training programs are implemented for skilled labor needs. However, some increase in local population may occur during construction and this increase, although temporary, will probabaly strain community services. Economic benefits accrued from wages and spending in the nearby communities may offset this strain to some extent; cooperation between the sponsoring utility and the region to absorb some of the costs for temporary housing and services may also be necessary.

The plant will generate power for export to the regional grid, allowing expansion of residential, commercial, and industrial development in the area and further expansion of local economies.

Table 43 summarizes the principal impacts of coal-to-power development and potential mitigation of adverse effects.

TABLE 43. SUMMARY ENVIRONMENTAL MATRIX — COAL TO POWER

Environmental Factors	Effect of Plant Construction and Operation	Potential Mitigating Measures
Climatology and Meteorology	Local fogging from cooling tower plume possible in periods of high humidity	
Air Quality	Localized fugitive dust, vehicle emissions from construction; small emissions of NO_x, SO_x, particulate, hydrocarbons during operation; coal handling, transport storage a potential source of fugitive (coal) dust	
Surface Water Availability	0.51 gal/kWh; minor adverse impact	
Surface Water Quality	Releases of TDS, TSS and chemicals — minor, localized impact in receiving water	
Groundwater Availability	No consumption — no effect	
Groundwater Quality	Potential leaching from coal storage piles, fly ash and bottom ash, and sludges	Management of landfill; including lining of ponds and basins, sealing of landfill cells, etc.
Land Availability	730 acres required; no significant regional impact	Care in siting to avoid sensitive or valuable areas
Regional Ecology and Critical Habitat	365 acres of vegetation and associated wildlife removed or disturbed; potential adverse secondary impacts during operation	Care in siting to avoid critical habitat, rare or endangered species

(Continued)

TABLE 43. (Continued)

Environmental Factors	Effect of Plant Construction and Operation	Potential Mitigating Measures
Aesthetic Resources	365 acres of industrial use in rural area — visual contrast, plant noise, increased traffic detract from rural character of area	Plant design, layout, landscaping, 365 acre buffer zone
Historical, Archaeological Resources	Insignificant impact	Care in siting to avoid likely sites of value; site protection and recovery plans
Community Economy	Substantial benefit from income, local capital expenditures and broadened tax base	
Community Population and Services	Potential for increase in local population during construction and resultant strain on services	Coordination of utility-community to provide temporary housing, subsidize services, etc.
Labor Availability	Requirements for construction personnel (1,000) and operation staff (95 full-time) — local manpower pool adequate	Labor training programs as necessary
Power Availability	Temporary consumption of power, fuels during construction; export power to grid during operation	
Transportation Availability	Access road, rail spur, barging facilities needed; transmission corridor needed	Careful selection of corridors to minimize impact

SECTION 4

SCENARIO 2 — STRAW/MANURE AND COAL TO SPG IN THE MIDWEST REGION

In this scenario, a 7 MM SCFD anaerobic digestion (biogas) plant and a 274 MM SCFD coal gasification (HYGAS) plant are to be constructed and operated at hypothetical sites in the midwest region of the U.S. Figure 15 indicates the regional location considered. The biogas plant feedstocks are wheat straw and cattle manure collected locally and delivered to the biogas plant. Subbituminous coal is shipped to the gasification plant from a strip mine in a western state. Both plants produce high-Btu synthetic pipeline gas (SPG). Product gas is piped a short distance offsite to an interstate gas line.

A regional environmental setting and brief plant site description are presented to provide a background for the environmental assessments. Principal environmental assumptions include:

- The proposed NSPS for steam-electric generation will apply
- Sulfur recovery units will have 99.8 percent sulfur capture
- Fugitive emissions of sulfur compounds are $\leq$ 500 ppmv as SO_2* and $\leq$ 10 ppmv H_2S
- Fuel gas will have $\leq$ 0.1 gr H_2S/dSCF
- Best available control technology (BACT) will apply to aqueous effluents
- Major residues from conversion will be disposed of offsite and are assumed to be nontoxic; the disposal costs are included in the feedstock costs
- No preconstruction environmental costs are included
- No costs for any emission offsets are included
- Product distribution costs and distribution impacts are excluded.

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*Higher than the proposed NSPS for sulfur recovery units (40 CFR60, Subpart J)

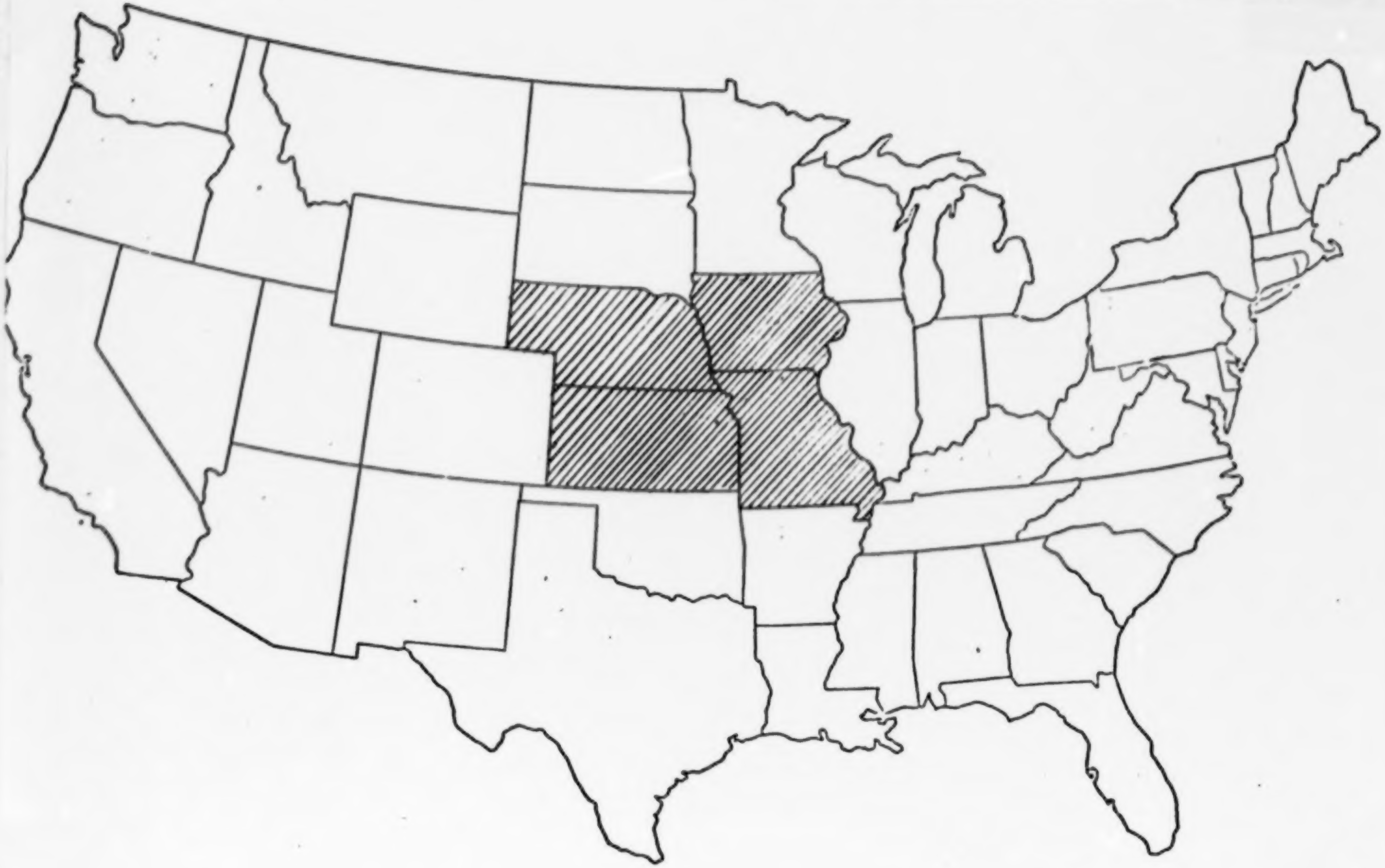

Figure 15. Straw/manure and coal to SPG region – Scenario 2.

REGIONAL ENVIRONMENTAL SETTING

The biomass and coal conversion plants will be located at a hypothetical site in the Northern Plains of the Midwest (e.g., in Kansas or Nebraska). The following describes the regional environmental setting of the plants.

Land Use

Broadly speaking, three land resource regions are represented. Approximately four-fifths of the land in western Kansas and about one-half of southern Nebraska is in the Central Great Plains Winter Whest and Range Region. About one-half of Nebraska north of the Platte River is in the Western Great Plains Range and Irrigated Region. The rest, immediately west of the Missouri River to the north and along the border of the state of Missouri, is in the Central Feed Grains and Livestock Region (22).

Nearly all the land is in farms and ranches. About one-half of the area is cropland. Hard winter wheat and grain sorghum are the main cash crops. Corn and alfalfa are also grown, mostly under irrigation. About two-fifths of the area is in range or pasture of native grasses, forks, and shrubs. Beef cattle are the principal livestock, though dairy cattle are also found in some areas.

Elevation and Topography

Large areas of nearly level to gently rolling plains are a dominant characteristic of the topography of the Northern Plains. This smooth relief is interrupted only occasionally by relatively small areas of land with steeper slopes. These areas of greater relief are often associated with the more prominent moraines or with dissection bordering the large streams. In some areas many of the larger east-flowing streams have formed badlands or steep, nearly barren eroded places such as in northwestern Nebraska. Sand dunes have also produced localized areas of rolling terrain. The most extensive of these is in the Sand Hills of Nebraska (23).

Climate

Cold to warm, temperate, semi-arid to humid continental climates characterize the North Central Region. Winters are fairly cold and summers warm or hot. A greater proportion of rainfall occurs during the spring and summer months. In the western part, the annual precipitation averages 15 to 20 inches or less. It increases, however, to the east and southeast and attains average values of 40 inches or more along the southeastern part of Kansas.

Along the northern border of the region the climate is cold. The average annual temperature there is below 40°F and the average frost-free period is less than 120 days. Both the temperature and the length of the frost-free period increase toward the south, where values of 55°F and 200 days for average annual temperature and the frost-free period are common. Frost penetrates to appreciably greater depth in the northwestern parts of the North Central Region than in the southern parts, particularly on bare ground. Consequently soil temperatures average appreciably lower in the northern part of the region (23).

One of the most serious climatic problems in the Great Plains is the wind. Windspeeds are highest in spring and cause soil blowing. Thunderstorms also occur over the region during summer, but they are less destructive than winds in their action on soil erosion.

Soils

Soils of the area are predominantly Mollisols, Entisols, Alfisols, and Utisols. Many have a subsurface horizon of accumulated clays and carbonates or salts. The soils in the Nebraska sandhills show weak pedogenic development and, consequently, become dry quickly during periods of drought; these soils are easily weatherable (16).

Vegetation

The soils in the area support a prairie-type of vegetation, although forest ecosystems may be found along watercourses and at higher elevations. The prairie vegetation may belong to one of a number of ecosystems; from west to east, they are:

- Grama - buffalo grass, dominated by blue grama *(Bouteloua gracilis)* and buffalo grass *(Buchloë dactyloides)*

- Wheatgrass - bluestem - needlegrass, dominated by western wheatgrass *(Agropyron smithii)*, big bluestem *(Andropogon gerardi)*, and needlegrass *(Stipa spartea)*

- Bluestem - grama, dominated by little bluestem *(Andropogon scaparius)*, side-oats grama *(Bouteloua curtipendula)*, and blue grama

- Bluestem, dominated by little bluestem, big bluestem, switchgrass *(Panicum virgatum)*, and Indian grass *(Sorghas trum nutans)*

Specialized soil conditions support variations of these prairies: the Nebraska Sandhills prairie ecosystem, the sandsage - bluestem prairie ecosystem, or the northern cordgrass ecosystem (24, 25).

The forest ecosystems of the area include the northern flood plains (cottonwood, black willow, American elm), the oak-hickory forest (white, red or black oaks, bitternut, or shagbark hickories), the oak-hickory-pine forest (hickory, shortleaf or loblolly pines, and white or post oaks), and the Cross Timbers area (groves of blackjack and post oaks in little bluestem prairie).

Wildlife

An unusual variety of wildlife and fish species is found in the region due to the variety of potential vegetation types intermixed with agricultural and pasture land uses. Deer are the most abundant big game, followed by antelope. Pheasant is the most important upland game species, followed in importance by bobwhite quail. Wetlands attract migrating waterfowl in large numbers (26).

BIOGAS PLANT SITE DESCRIPTION

The plant site is in a rural area on purchased farmland. This area is called the subhumid wheat region of the Great Plains.

Topography and Elevation

The site is nearly level and adjacent to a broad flood plain of a major local river. The surrounding topography is undulating to gently rolling, and some areas adjacent to the major drainage have slopes of as much as 15 percent. The site is approximately 1400 feet above mean sea level.

Transportation

A state highway passes within a mile and a half of the plant and connects it with a network of state highways and county roads. A major rail network is accessible within two miles of the plant site. The nearest town is about two miles north of the plant. A major population center (greater than 250,000) lies 15 miles north of the plant. Two natural gas pipelines cross within three miles of the plant. These connect with other major and secondary pipelines in the area.

Climate and Air Quality

The climate at the site is typical of the Great Plains. Table 44 summarizes pertinent climatic conditions. Air quality at the site is characterized as generally good. Currently, ambient air quality standards are not being met for photochemical oxidants and carbon monoxide. The standard for particulate matter is sometimes exceeded locally.

Land Use

Land surrounding the plant is in farms with approximately two-thirds of the area under crops. Wheat is by far the most extensively grown crop, but large acreages of grain sorghum and alfalfa are also grown. Corn is a major crop north of the site. A little more than two-fifths of the area west of the site is in range or pasture of native grasses and shrubs. East of the site, about one-fourth of the land is in range or pasture and grazed by beef cattle. Some dairy cattle are also found in the area.

Plant Water Resources

River flow at the plant averages 1095 cfs with a minimum annual daily discharge of 120 cfs. The water is high in dissolved solids content and alkalinity (see Table 45). Mean annual temperature is 62°F with 33°F to 84°F (daily) range. All of the plant water requirements will be supplied by the river, with the exception of potable water, which will be pumped from shallow wells drilled on the site. The plant elevation is about 50 feet above the normal river water level.

TABLE 44. ASSUMED CLIMATIC CONDITIONS AT THE SITE

Elevation:	1400 feet
Temperature:	
Annual Average	57°F dry bulb 50°F wet bulb
5-Percent Design Conditions	95°F dry bulb 75°F wet bulb
Annual Minimum (Design)	-10°F
Annual Extremes (Daily)	23°F to 92°F
Prevailing Wind:	South at 13.5 mph (mean)
Precipitation:	
Annual Precipitation	30.7 inches
Annual Runoff	5 inches
Annual Lake Evaporation	56 inches
10-yr, 24-hr Storm	5 inches
Average Frost-Free Period:	190 days

Soils

The soils of the subhumid wheat region have a high proportion of productive soils which have consistently produced more wheat per acre of farmland than any other soils in the northern Great Plains (14).

The soils at and around the site are Hapludolls and Arguidolls based on the latest soil classification system (22, 27). Both great soil groups are Mollisols, very dark in color and rich in bases. The association includes deep and moderately deep, nearly level to undulating and hummocky soils on low terraces and uplands. Most soils are coarse-textured and highly erodible.

These soils are used chiefly for dryland farming and range. Conservation of moisture, control of erosion, and maintenance of fertility are the major management needs. They are accomplished by proper use of crop residues, wind strip cropping, the growing of cover crops, contour farming, minimum tillage, and fertility control.

TABLE 45. ASSUMED AVERAGE RIVER WATER QUALITY

Component	Value
Flow, Average Discharge	1,095 cfs
Flow, Minimum Daily	120 cfs
pH	7.9
Temperature	62°F
Turbidity	60 JTU
Dissolved Oxygen	10.2 mg/l
Chemical Oxygen Demand	48 mg/l
Calcium	79 mg/l
Magnesium	17 mg/l
Sodium	244 mg/l
Potassium	8 mg/l
Bicarbonate	238 mg/l
Carbonate	0 mg/l
Sulfate	123 mg/l
Chloride	469 mg/l
Phosphorus	1.6 mg/l
Nitrate + Nitrite - Nitrogen	1.0 mg/l
Ammonia Nitrogen	1.7 mg/l
Total Organic Nitrogen	2.5 mg/l
Total Dissolved Solids	1,094 mg/l

Vegetation

Rangeland now occupies approximately one-third of the farmland around the area and is used for livestock grazing. Large areas of range occur along the river. The wood species growing along most of the streams and drainage ways are represented by cottonwood, green ash, and wild plum, but the principal vegetation on range soils still remains the native grass. The climax plant cover on flood plains and stream terraces consists of a mixture of such salt-tolerant grasses as switchgrass, Indian grass, alkali scaton, western wheatgrass, tall dropseed, prairie cordgrass, vine mesquite, and saltgrass. Commonly grown windbreak trees in the area include the American plum, bur oak, catalpa, cottonwood, eastern redcedar, green ash, hackberry, honeylocust, mulberry, osage orange, ponderosa pine, Russian olive, and Siberian elm (28).

Wildlife

Deer are present today and are probably more numerous than 100 years ago, owing to better feed availability and protection by game laws. Ring-necked pheasant, mourning dove, and fox squirrel are now numerous thanks to changes in vegetation due to a changed land use.

Fish, cottontail rabbit, ring-necked pheasant, and bob-white quail are important game species. Other animals include raccoon, badger, opossum, skunk, gray squirrel, fox squirrel, coyote, jackrabbit, beaver, muskrat, mink, and waterfowl.

Large streams provide ample fishing and recreational opportunity, mainly for several species of catfish.

WHEAT STRAW AND MANURE PROCUREMENT

Wheat Straw

Hard red winter wheat is extensively grown in the area around the proposed plant site. The state produced one-fifth of the entire U.S. wheat crop and ranked first in the nation. The county where the site is proposed is a consistent leader as the top wheat producing area. The surrounding five counties are also leaders in wheat production (29).

Winter wheat in the site area is usually seeded between September 15 and about October 10 and harvested from June 10 to July 1. Nearly all straw is left in the fields to protect soils from wind and water erosion and later buried in the surface soil by moldboard plows. The average yield of grain in the area is around 33 to 35 bushels per acre (or about 1 ton/acre). A rule of thumb used for estimating straw produced by a wheat crop is a straw-grain ratio of 1.7 (100 lb straw/bushel of wheat) (30), although winter wheat may attain a straw-grain ratio of 2.0 (120 lb straw/bushel of wheat) (31). Approximately two million tons of wheat residues are returned to the soil in the five counties surrounding the plant. Since the conversion plant will consume only about 330,000 tons/yr of wheat straw, there is ample supply available for feedstock provided it could be removed without any harmful effects on the soil.

Since little wheat straw is currently collected in the region, wheat straw procurement for the plant is to be specially induced in the area. The twenty-year plant life should be enough incentive for independent capital investment in wheat straw collection, yarding (storage), and transport equipment.

After wheat harvesting, farmers or independent contractors bale the straw residue mechanically and load the bales on trailers for transport to roadside. Bales may be stacked and stored by individual farmers or loaded on trailer trucks for transport to contractor-owned yarding facilities in the area. At this period in the year, virtually all of the plant's annual feedstock requirement is offsite, distributed throughout the area in various storage facilities. As needed during the year, the yarded bales are loaded on truck-trailers mechanically and delivered to the conversion plant.

At a wheat straw field density of 1.5 tons/acre/year, a minimum of about 220,000 acres of cropland is subject to residue collection. In fact, much more area is involved since complete collection is not desirable.

Manure

The annual plant requirement is about 330,000 tons (wet)* of livestock manure. Currently most of the manure in the region is not classified as waste material, being deposited on the land as a fertilizer. There is reportedly about 78,000 tons per year (dry basis) of manure potentially available in five counties surrounding the plant (32). Nearly 65 percent of this is needed by the conversion plant, since fresh manure is about 85 percent moisture, and 15 percent dry solids.

Livestock production (mainly beef and dairy cattle) is a major agricultural industry in the area because of the proximity of large quantities of feed crops. Large, confined feed lots (greater than 10,000 head) are not predominant, but intermediate-sized feed lots are spread throughout the area. Unconfined pastureland accounts for the remainder of the livestock production. In this scenario, manure is purchased on a delivered tonnage basis to the plant. As in the case of wheat straw procurement, procurement is to be an induced independent industry with the incentive of a long-term demand. Independent suppliers contract with ranchers for pickup rights to manure collected and stockpiled. Collection service is provided by front-end loaders and trailer trucks; no yardage facilities are normally used by the suppliers.

BIOGAS PROCESS DESCRIPTION (ANAEROBIC DIGESTION)

Summary

The biogas plant produces about seven million standard cubic feet per day (SCFD) of methane gas from 1000 tons per day of wheat straw and 1000 tons per day of cattle manure by anaerobic digestion. Wheat straw and cattle manure are purchased by the plant on a contract basis from farmers in the region and delivered to the plant at a per-ton unit price.

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*Equivalent to 49,500 tons on a dry basis.

The biogas plant converts the feedstocks to pipeline quality fuel gas and waste solids. Some of the digester gas (raw gas) is used within the plant to generate process steam. The remaining raw gas is compressed and treated to produce pipeline quality gas (4870 SCFM) having a heating value of 950 Btu/SCF. The sulfur content is 15 ppmv H_2S and the moisture content is 200 ppmv or less. The treated gas at 320 psia is piped three miles to the nearest gas pipeline. The waste solids - 534 tons per day (dry) of undigested materials - are dewatered and trucked away to farmlands to be used as soil conditioner. The plant boundaries are indicated by the fenced area in Figure 16.

The process description is divided into feedstock receiving and preparation, digestion and effluent treatment, gas cleaning, and auxiliary facilities. The principal design bases and assumptions are summarized below.

Design Basis

There have been many research and development projects on anaerobic digestion of organic materials for methane gas production. These have been primarily laboratory studies, quite insufficient to provide the data necessary for design of a full-scale biogas plant, especially a plant using wheat straw and cattle manure. In order to develop the conceptual design of the biogas plant for this study, numerous assumptions and simplifications had to be made on the feedstock characteristics, reaction rate, reaction conditions, and properties of materials at various process stages.

The plant capacity is somewhat arbitrary. The size is somewhat limited by the quantity of feedstock that can reasonably be collected in the area and can reasonably be accommodated in the plant without severe handling problems.

The assumed characteristics of the feedstocks as they are received at the biogas plant are presented in Table 46. Design and operating criteria for each of the process sections are summarized in Tables 47 through 50.

Feedstock Receiving and Preparation

Wheat Straw Receiving and Storage--

An average of 1000 tons per day of wheat straw is consumed in the plant. The receiving facilities are designed to operate six days per week and two shifts per day. A heavy delivery of wheat straw is expected during a period immediately after the harvest season. The remainder of the baled straw is yarded offiste by the straw suppliers. The delivery will be somewhat reduced as the next harvest season is approached. A bale storage facility (60 days storage capacity) is provided at the plant site. Figure 17 depicts the feedstock receiving and preparation operations.

Wheat straw is delivered to the plant by end-dump trailer trucks of 2000-cubic-foot capacity. The trucks are unloaded by hydraulic dump platforms which raise the truck-and-trailer allowing the bales to discharge by gravity into the hopper pit.

The wheat straw receiving ramp is provided with five hydraulic dump platforms. The trucks back onto the platforms and discharge their loads as the platforms raise. The dump cycle of each platform is about ten minutes.

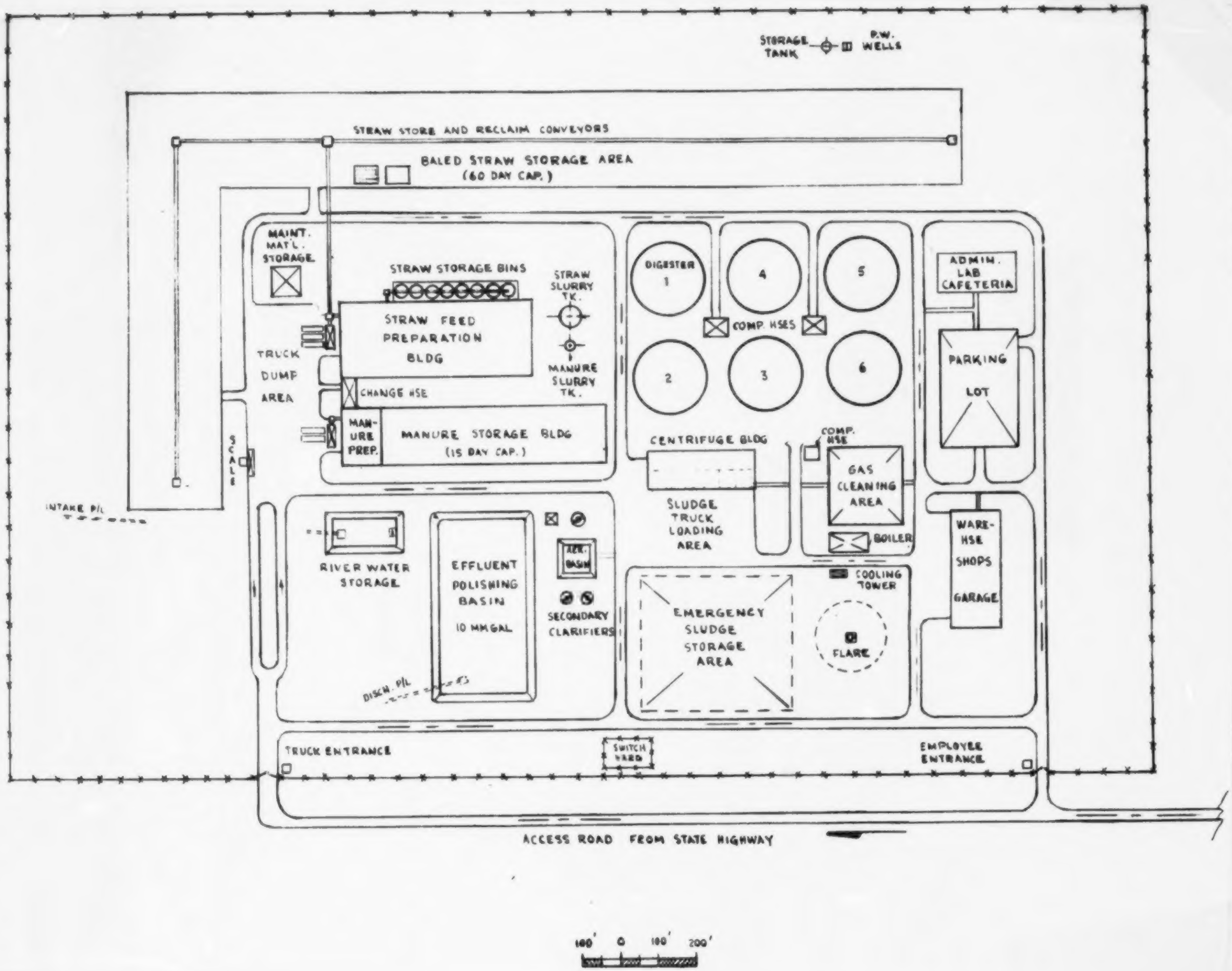
STORAGE TANK
P.W. WELLS
STRAW STORE AND RECLAIM CONVEYORS
BALED STRAW STORAGE AREA (60 DAY CAP.)
MAINT. MAT'L. STORAGE
STRAW STORAGE BINS
STRAW SLURRY TK.
STRAW FEED PREPARATION BLDG
MANURE SLURRY TK.
TRUCK DUMP AREA
CHANGE HSE
MAN-URE PREP.
MANURE STORAGE BLDG (15 DAY CAP.)
SCALE
INTAKE P/L
DIGESTER 1
2
3
4
5
6
COMP. HSES
CENTRIFUGE BLDG
COMP. HSE
SLUDGE TRUCK LOADING AREA
GAS CLEANING AREA
BOILER
ADMIN. LAB CAFETERIA
PARKING LOT
WARE-HSE
SHOPS
GARAGE
RIVER WATER STORAGE
EFFLUENT POLISHING BASIN 10 MMGAL
AER. BASIN
SECONDARY CLARIFIERS
DISCH. P/L
EMERGENCY SLUDGE STORAGE AREA
COOLING TOWER
FLARE
TRUCK ENTRANCE
SWITCH YARD
EMPLOYEE ENTRANCE
ACCESS ROAD FROM STATE HIGHWAY
100'
0
100'
200'

Figure 16. Straw/manure to gas, general plant arrangement.

120

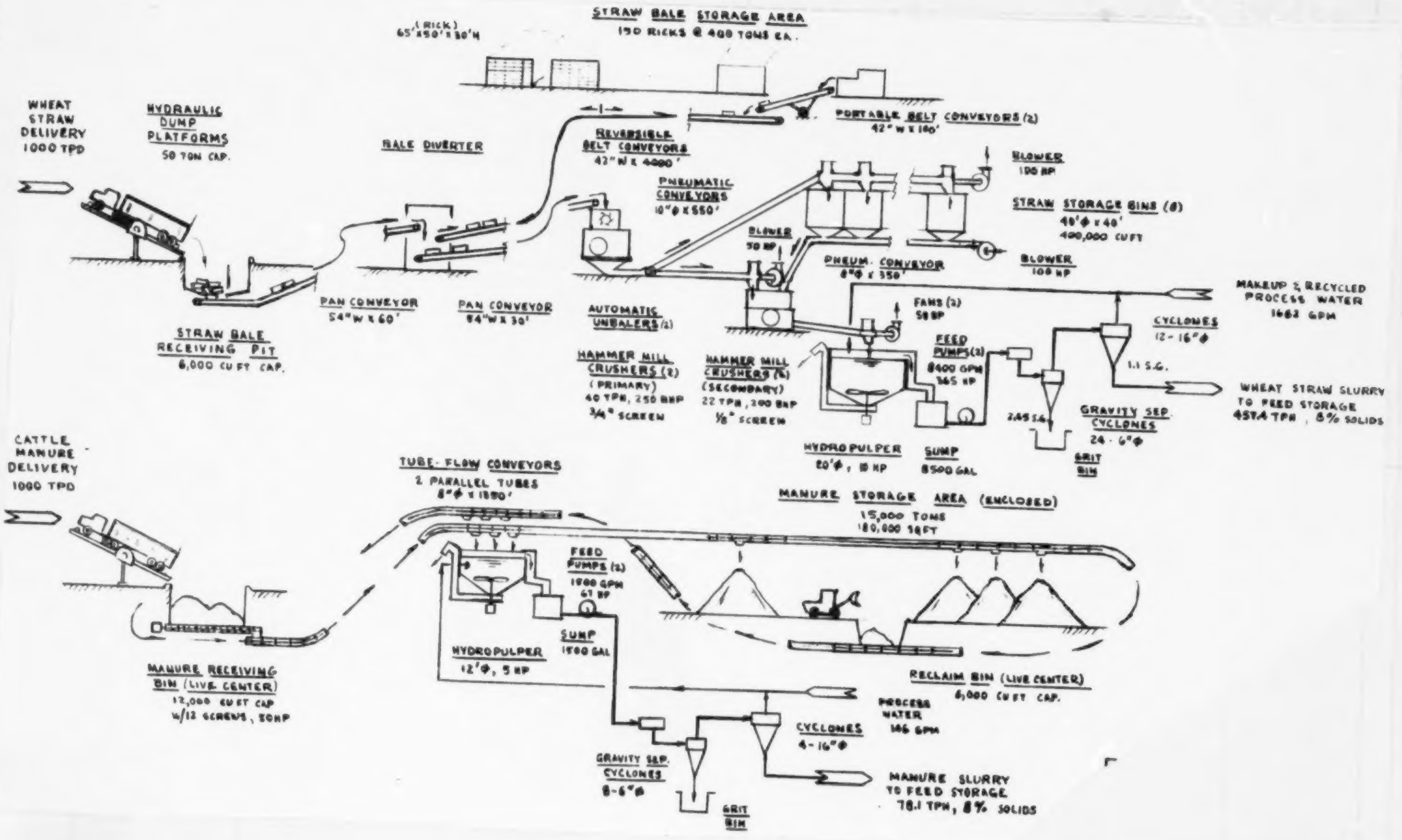
STRAW BALE STORAGE AREA
190 RICKS @ 400 TONS EA.
(RICK)
65'X50'X30'H
WHEAT
STRAW
DELIVERY
1000 TPD
HYDRAULIC
DUMP
PLATFORMS
50 TON CAP.
BALE DIVERTER
REVERSIBLE
BELT CONVEYORS
42"W X 4000'
PORTABLE BELT CONVEYORS (2)
42"W X 160'
PNEUMATIC
CONVEYORS
10"ϕ X 550'
BLOWER
100 HP
STRAW STORAGE BINS (8)
40'ϕ X 40'
400,000 CU FT
BLOWER
50 HP
PNEUM. CONVEYOR
8"ϕ X 350'
BLOWER
100 HP
STRAW BALE
RECEIVING PIT
6,000 CU FT CAP.
PAN CONVEYOR
54"W X 60'
PAN CONVEYOR
84"W X 30'
AUTOMATIC
UNBALERS (2)
HAMMER MILL
CRUSHERS (2)
(PRIMARY)
40 TPH, 250 BHP
3/4" SCREEN
HAMMER MILL
CRUSHERS (2)
(SECONDARY)
22 TPH, 200 BHP
1/8" SCREEN
FANS (2)
50 HP
FEED
PUMPS (2)
8400 GPM
365 HP
MAKEUP & RECYCLED
PROCESS WATER
1662 GPM
CYCLONES
12 - 16"ϕ
1.1 S.G.
2.45 S.G.
WHEAT STRAW SLURRY
TO FEED STORAGE
457.4 TPH, 8% SOLIDS
GRAVITY SEP.
CYCLONES
24 - 6"ϕ
GRIT
BIN
HYDROPULPER
20'ϕ, 10 HP
SUMP
8500 GAL
CATTLE
MANURE
DELIVERY
1000 TPD
TUBE-FLOW CONVEYORS
2 PARALLEL TUBES
8"ϕ X 1350'
MANURE STORAGE AREA (ENCLOSED)
15,000 TONS
180,000 SQ FT
FEED
PUMPS (2)
1500 GPM
67 HP
SUMP
1500 GAL
HYDROPULPER
12'ϕ, 5 HP
MANURE RECEIVING
BIN (LIVE CENTER)
12,000 CU FT CAP
W/12 SCREWS, 50 HP
RECLAIM BIN (LIVE CENTER)
6,000 CU FT CAP.
PROCESS
WATER
146 GPM
CYCLONES
4 - 16"ϕ
GRAVITY SEP.
CYCLONES
8 - 6"ϕ
GRIT
BIN
MANURE SLURRY
TO FEED STORAGE
78.1 TPH, 8% SOLIDS

Figure 17. Straw/manure receiving and feed preparation section.

TABLE 46. ASSUMED CHARACTERISTICS OF FEEDSTOCKS

Composition	Wheat Straw	Cattle Manure
Proximate		
Moisture, % wt	12.2	85.0
Ash, % wt	7.2	3.1
Volatile Solids, % wt	80.6	11.9
	100.0	100.0
Bulk Density, lb/cu ft	12	62
Ultimate		
Hydrogen, % wt	5.6	5.3
Carbon, % wt	44.8	37.5
Sulfur, % wt	0.2	0.3
Nitrogen, % wt	0.5	2.1
Oxygen, % wt	44.7	34.1
Ash, % wt	8.2*	20.7**
	100.0	100.0
Heating Value (HHV), Btu/lb	9,736 (dry)	8,168 (dry)
	9736	8168

* Phosphorus in ash - 0.1% wt.
** Phosphorus in ash - 0.4% wt.

TABLE 47. DESIGN AND OPERATING CRITERIA - FEED PREPARATION

Feedstock Delivery	Wheat Straw Trucks - 2000 cu ft capacity Cattle Manure Trucks - 20 tons capacity
Feedstock Storage at Plant	Wheat Straw - 60 days on open gravel area Cattle Manure - 15 days in building
Size Reduction	Wheat Straw - crushed to 1/8 inch by hammermills, then pulped by hydropulper Cattle Manure - pulped by hydropulpers
Feed Slurry	Wheat Straw and Cattle Manure - 8% solid slurry
Feed Slurry Storage	Wheat Straw Slurry - 4 hours Cattle Manure Slurry - 4 hours
Facility Operation	Feedstock Receiving - 2 shifts/day and 6 days/week Size Reduction - 3 shifts/day and 7 days/week

TABLE 48. DESIGN AND OPERATING CRITERIA - DIGESTION

Feed	12,850 tons/day slurry (1,028 tons/day total solids, 925 tons/day volatile solids)
Detention Time	10 days
Temperature	95°F, controlled with steam/hot water
pH	6.5 to 7.5, controlled with lime (0.02 lb lime per lb of dry solid in feed)
Biological Conversion	6.94 SCF product gas per lb of volatile solids (VS) (6.5 SCF/lb of VS in cattle manure and 7.0 SCF/lb of VS in wheat straw); product gas contains 60% methane, 38.9% carbon dioxide, 1% hydrogen, and 0.1% hydrogen sulfide (dry basis)
Digester Effluent	12,566 tons/day slurry containing 593.5 tons/day total solids
Digester Mixing	Compression and recycle of raw product gas through special draft-tube heater-mixers, 0.16 SCFH/cu ft of digester volume

TABLE 49. DESIGN AND OPERATING CRITERIA - GAS CLEANING

Feed	Maximum 12.8 MM SCFD (dry) raw gas feed (design average of 11.3 MM SCFD) containing 60% CH_4, 38.9% CO_2, 1.0% H_2 and 0.1% H_2S (dry basis; 325 psia
Product	Design average of 7.0 MM SCFD fuel gas containing 93.6% CH_4, 4.88% CO_2, 1.5% H_2, $\leq$15 ppm H_2S, and $\leq$200 ppm H_2O; 320 psia, 950 Btu/SCF (dry)
Gas Cleaning	A package gas cleaning system based on "hot potassium carbonate acid gas absorption/regeneration"; the system design capacity is 13.5 MM SCFD of raw gas
Gas Dehydration	A package dehydration system based on "glycol water absorption/regeneration"; the system is designed for 7.2 MM SCFD feed gas
Acid Gas	A package gas incineration system sized for incineration of 3,400 SCFM acid gas (0.44% CH_4, 99.3% CO_2, and 0.28% H_2S); the system is also provided with a waste heat boiler generating 6,000 lb/hr low pressure steam

TABLE 50. DESIGN AND OPERATING CRITERIA - EFFLUENT TREATMENT

Digester Effluent Dewatering	
Centrifuge	12,600 tons/day feed (594 tons/day solid), 29% solid cake product, 0.5 hp/gpm power requirement
Centrate Recirculation	80% of the centrate is returned directly to the feed preparation facility
Cake Storage	432,000 cu ft storage bins
Wastewater Treatment	
Wastewater	360,000 gal/day containing 4000 mg/l SS and 800 mg/l BOD
Primary Clarifier	600 gal/day/sq ft, 13,000 mg/l SS underflow, 90% SS removal
Aeration System	400,000 gal aeration tank, 4800 lb/day oxygen, 24 hours detention 2000 mg/l MLVSS, and 90% BOD reduction
Secondary Clarifier	600 gal/day/sq ft, 10,000 mg/l SS underflow, 90% SS removal
Polishing Pond	30 days detention; the pond effluent can be discharged to the receiving stream or to the process makeup waste system

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Wheat straw bales dropped into the hopper pit are transferred to the size reduction facility by a combination of a 54-inch belt conveyor and a 42-inch belt conveyor. Wheat straw handling is shown in Figure 17.

When the straw is to be diverted to the storage area, a 42-inch belt conveyor (reversible) brings bales to the storage area and then a 42-inch portable belt conveyor is used to direct the bales for stacking. These conveyors are reversible and can also bring out the stored bales for processing.

Wheat Straw Storage--

The storage of wheat straw for 60 days of operation is equivalent to 10 million cubic feet of baled straw. The storage area, approximately 250 feet wide and and 3200 feet long, is provided with a reversible 42-inch belt conveyor system which delivers the bales from the receiving area for storage and also transfers the stored bales to the feed preparation area when the stored bales are to be processed.

The bales are stacked about 30 feet high (20 bales) on both sides of the belt conveyor. Two auxiliary portable belt conveyors (42 inches wide and 100 feet long) are used to stack the bales. The bale storage area is gravel-based to provide easy draining.

Wheat Straw Feed Preparation--

To obtain a high biological conversion of the wheat straw, it is pulverized to submillimeter-size fibers before feeding to the digesters. The straw size reduction is a three-step process — preliminary shredding (hammermills), secondary shredding (hammermills), and pulping (hydropulpers).

The bales brought to the size-reduction facilities are first unbaled automatically and then fed to two primary shredders (hammermills) of 40-ton-per-hour capacity. The primary shredders are operated two shifts per day. Each shredder is equipped with discharge grates to produce 1½-inch top size straw pieces (80 percent minus 3/4-inch length).

The straw from the primary shredders is transferred to the secondary shredders by a penumatic conveyor. The straw is further crushed in the secondary shredders (two 22-ton-per-hour hammermills) to about 90 percent, minus 1/8-inch size. The shredded straw is transferred to a 20-foot diameter hydropulper by a pneumatic conveyor for the final size reduction. The hydropulper reduces the straw to submillimeter sizes. The pulped wheat straw is then degritted and concentrated by cyclones.

The first set of hydrocyclones removes the grit in the slurry and the second set (twelve 16-inch diameter units) concentrates the straw slurry to eight-percent solids content. The overflow from the second set of hydrocyclones is returned to the hydropulper. The pulped, degritted, and concentrated wheat straw (slurry) is pumped to the digester feed surge tank.

Wheat straw receiving and unloading is a two shifts per day and six days per week operation, while the primary shredding is a two shifts per day and seven days per week operation. During the weekends, the bales from the storage area are brought to the primary shredders. The secondary shredding and hydropulping is a three shifts per day and seven days per week (continuous) operation.

Eight 40-foot diameter by 40-foot high bins provide 400,000 cubic feet of capacity to store shredded straw from the primary shredder. During the third shift, the straw is transferred to the secondary shredder by an eight-inch diameter pneumatic conveyor.

Cattle Manure Receiving and Storage--

An average of 1000 tons per day* of cattle manure is delivered to the plant. Cattle manure is delivered to the plant by 20-ton dump trucks which unload the contents into a receiving bin. The receiving bin is provided with two screw conveyors which transfer cattle manure to a tube conveyor system. The cattle manure handling is shown in Figure 17.

The conveyor system, consisting of two 2500-foot long, eight-inch diameter tube sections, is designed to transfer cattle manure from the receiving area to the feed preparation facility where the feedstock is subjected to size reduction and degritting. The conveyor system also transfers the feedstock to the storage facility. The returning section of the conveyor is used to transfer the stored manure to the feed preparation area when the stored manure is to be processed.

During normal operation, delivery and unloading are carried out two shifts per day and six days per week. During the third shift and on weekends, the manure in the receiving bin is processed first until the bin is empty, and then manure from the storage facility is transferred to the preparation facility for processing.

The manure conveyor system is a special type. It consists of a continuous tube in which flat discs connected to a continuously travelling chain are mechanically pulled by a driving mechanism. The feedstock is pushed by the discs until it reaches a discharge opening. The enclosed tubular conveyor minimizes the odor problem and potential spills.

The manure transferred to the pulper is discharged directly into the pulper feed hopper. By closing the discharge valve, the manure can be conveyed to the storage area. By selectively opening the discharge valves on the overhead tube line, the manure can be deposited by free fall into a series of overlapping conical piles.

When stored manure is to be processed, a front-end loader pushes it from the piles into a loading bin recessed in the floor. The manure is then fed into the returning tube conveyor line which transfers it to the feed preparation facility.

The cattle manure storage facility consists of a building with a concrete floored area 150 feet wide by 600 feet long. The storage area is enclosed to house the overhead tube conveyor lines and also to prevent a potential runoff problem. A part of the returning tube conveyor is installed under the floor. Two independently operated conveyor systems allow effective use of the storage area and uninterrupted plant operation.

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*Equivalent to 150 tons per day on a dry basis.

Cattle Manure Feed Preparation--

Manure feed preparation involves size reduction, degritting, and slurry feed concentration. The manure is fed to a 12-foot diameter hydropulper directly from the tube conveyor discharge opening. The pulped slurry is then pumped to two sets of hydroclones. The first set (four 6-inch diameter units) removes grit and the second set (four 12-inch diameter units) concentrates the slurry to eight percent solids content. The overflow from the second set is returned to the pulper. The pulped, degritted, and concentrated cattle manure slurry is pumped to the digester feed surge tank.

Anaerobic Digestion and Effluent Treatment Facilities

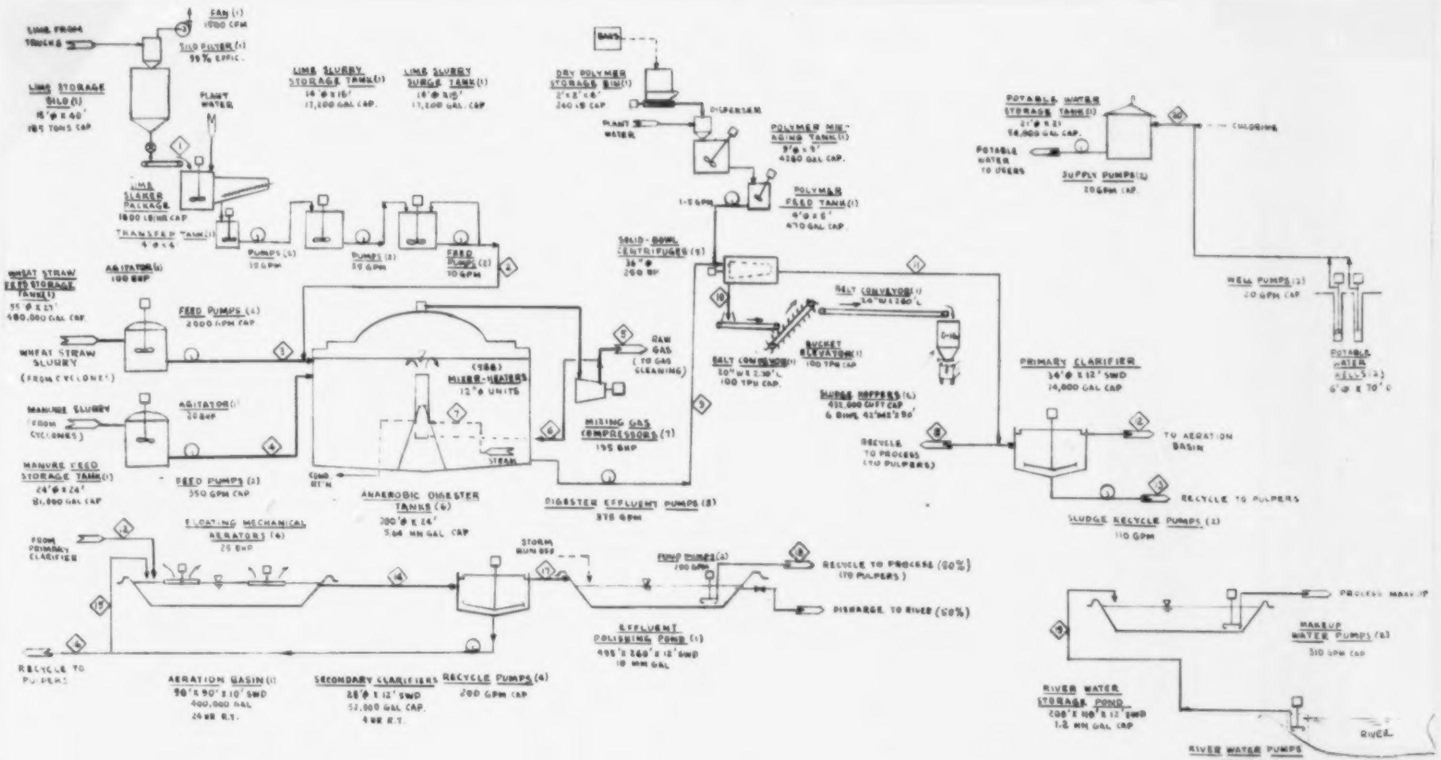
Wheat straw and cattle manure in slurry form are pumped to storage tanks (Figure 18). The wheat straw storage tank design capacity of 480,000 gallons provides four hours detention time. The manure slurry storage tank capacity is 81,000 gallons and also provides four hours detention time. Wheat straw slurry and cattle manure slurry are pumped by 2000 gpm and 350 fpm pumps respectively to six anaerobic digesters. Each digester is 200 feet in diameter and 24 feet tall (5.6 million gallons capacity) and together they provide a detention time of 10 days. The digesters are equipped with fixed concrete roofs and are insulated to minimize heat loss.

The pH of the digester contents is monitored continuously by probes and is maintained within the range of 6.6 to 7.0 by the addition of lime to the digester influent. The lime is supplied as a 10-percent slurry from a package unit consisting of a storage silo, weight feeder, feed conveyor, slaker, transfer tank, slurry storage tank, slurry surge tank, agitators, and pumps. The slaker capacity is 1600 pounds of lime per hour.

Sludge distribution and thermal homogeneity are provided by heater/mixers which use the raw product gas of anaerobic digestion. A portion of the product gas is used to fire a boiler, while another portion is compressed and recirculated through the mixing units. Compressed gas is released in the form of large bubbles into a stack in the lower portion of the digester. Each rising bubble forces liquid above it up through the stack while drawing liquid behind it. After leaving the stack, the bubble travels freely to the liquid surface. Heat is transferred to the sludge from a hot-water jacket surrounding the stack pipe. A bubble is emitted into the stack just before the preceding bubble leaves, thus providing continuous flow. Each digester is provided with 98 twelve-inch diameter heating and mixing units, and each unit is supplied with gas at 18 SCFM. Seven 195-horsepower compressors (including one installed spare) supply the gas to the heating-mixing units. The temperature of the digester contents is maintained at approximately 95°F by using 14,000 pounds per hour of 75 psig steam.

Product gas is released in the gas space under the digester cover, and is collected for recirculation and cleaning. The nutrients required for bacterial activity are contained in the feed to the digesters.

The liquid effluent from each digester is transferred by a 375 gpm progressive cavity pump to centrifuges for dewatering. Five 250-horsepower centrifuges, including one installed spare, are supplied. Polymer is added to the centrifuge feed to improve the dewatering characteristics of the solids. The polymer


LIME FROM TRUCKS
FAN (1) 1900 CFM
SILO FILTER (1) 99% EFFIC.
LIME STORAGE SILO (1) 15'Ø x 40' 185 TONS CAP
PLANT WATER
LIME SLAKER PACKAGE 1800 LB/HR CAP
TRANSFER TANK (1) 4'Ø x 4'
LIME SLURRY STORAGE TANK (1) 14'Ø x 15' 17,200 GAL CAP.
LIME SLURRY SURGE TANK (1) 16'Ø x 15' 17,200 GAL. CAP
PUMPS (2) 35 GPM
PUMPS (2) 35 GPM
FEED PUMPS (2) 10 GPM
AGITATOR (4) 100 BHP
WHEAT STRAW FEED STORAGE TANK (1) 55'Ø x 27' 480,000 GAL CAP
FEED PUMPS (4) 2000 GPM CAP
WHEAT STRAW SLURRY (FROM CYCLONES)
MANURE SLURRY FROM CYCLONES)
AGITATOR (1) 20 BHP
MANURE FEED STORAGE TANK (1) 24'Ø x 24' 81,000 GAL CAP
FEED PUMPS (2) 350 GPM CAP
(188) MIXER-HEATERS 12"Ø UNITS
STEAM
COND RT'N
ANAEROBIC DIGESTER TANKS (6) 200'Ø x 24' 5.64 MM GAL CAP
RAW GAS (TO GAS CLEANING)
MIXING GAS COMPRESSORS (7) 195 BHP
DIGESTER EFFLUENT PUMPS (8) 375 GPM
BAGS
DRY POLYMER STORAGE BIN (1) 2'x2'x6' 240 LB CAP
PLANT WATER
DISPERSER
POLYMER MIX-AGING TANK (1) 9'Ø x 9' 4280 GAL CAP.
POLYMER FEED TANK (1) 4'Ø x 5' 470 GAL CAP.
1-5 GPM
SOLID-BOWL CENTRIFUGES (9) 36"Ø 250 HP
BELT CONVEYOR (1) 24"W x 260'L
BELT CONVEYOR (1) 20"W x 230'L 100 TPH CAP.
BUCKET ELEVATOR (1) 100 TPH CAP
SLUDGE HOPPERS (6) 432,000 CUFT CAP 6 BINS 42'x42'x50'
RECYCLE TO PROCESS (TO PULPERS)
PRIMARY CLARIFIER 34'Ø x 12' SWD 14,000 GAL CAP
TO AERATION BASIN
RECYCLE TO PULPERS
SLUDGE RECYCLE PUMPS (2) 110 GPM
POTABLE WATER STORAGE TANK (1) 21'Ø x 21' 54,000 GAL CAP.
POTABLE WATER TO USERS
SUPPLY PUMPS (2) 20 GPM CAP.
CHLORINE
WELL PUMPS (2) 20 GPM CAP
POTABLE WATER WELLS (2) 6'Ø x 70'D
FROM PRIMARY CLARIFIER
FLOATING MECHANICAL AERATORS (4) 25 BHP
RECYCLE TO PULPERS
AERATION BASIN (1) 90'x90'x10' SWD 400,000 GAL 24 HR R.T.
SECONDARY CLARIFIERS 28'Ø x 12' SWD 52,000 GAL CAP. 4 HR R.T.
RECYCLE PUMPS (4) 200 GPM CAP
STORM RUN OFF
POND PUMPS (2) 200 GPM
RECYCLE TO PROCESS (50%) (TO PULPERS)
DISHARGE TO RIVER (50%)
EFFLUENT POLISHING POND (1) 495'x260'x12' SWD 10 MM GAL
PROCESS MAKE UP
MAKEUP WATER PUMPS (2) 310 GPM CAP
RIVER WATER STORAGE POND 200'x110'x12' SWD 1.2 MM GAL CAP
RIVER
RIVER WATER PUMPS 310 GPM CAP
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20

DESCRIPTION / COMPONENT	① LIME TO SLAKER	② LIME SLURRY FEED	③ STRAW SLURRY FEED	④ MANURE SLURRY FEED	⑤ RAW PRODUCT GAS	⑥ MIXING GAS	⑦ STEAM TO HTRS	⑧ CENTRATE RECYCLE	⑨ DIGESTER EFFLUENT	⑩ CENTRIFUGE SLUDGE	⑪ CENTRATE	⑫ PRIMARY CLARIFIER OVERFLOW	⑬ PRIMARY SLUDGE	⑭ AERATION BASIN EFFLUENT	⑮ RECYCLE SLUDGE TO BASIN	⑯ WASTE SLUDGE TO PROC.	⑰ SECONDARY CLARIFIER OVERFLOW	⑱ POLISHING POND EFFLUENT	⑲ RIVER WATER	⑳ POTABLE AND BFW
FLOW																				
TOTAL, TPD	18.5	185.0	10,978	1,875	471.9	537.6	169.4	8,625.3	12,566.1	1,839.8	10,786.5	1501.0	600.0	-	-	-	-	-	-	-
SOLIDS, TPD	18.5	18.5	878	150	-	-	-	52.7	593.5	534.1	59.4	0.6	6.1	-	-	-	-	-	-	-
WATER, TPD	-	166.5	10,100	1,725	18.9	21.5	169.4	8,572.6	11,972.6	1,305.7	10,664.5	1,500.4	593.9	2,491.9	990.9	120	1,381	1,381	1,187.4	96
WATER, GPM		27.7	1,682	287	3.1	3.6	28	1,428	1,994	217	1,776	250	99	415	165	20	230	230	198	16
BOD, LB/DAY	-	-	-	-	-	-	-	-	-	-	16,950	2,400	-	400	-	-	210	55	-	-
TSS, LB/DAY	-	-	-	-	-	-	-	-	-	-	-	1,200	-	22,234	20,016	3,426	110	70	-	-
GAS, MM SCFD	-	-	-	-	12.8	15.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Figure 18. Straw/manure to gas, process flow sheet, digesters and waste treatment.

is fed from a package system consisting of a dry polymer storage bin, feeder, disperser, mixing-aging tank, feed tank, agitators, and metering pump. Approximately 10 pounds of dry polymer are added per hour.

The centrifuge sludge cake (29 percent solids) is transported by a series of conveyors to a sludge hopper of 432,000-cubic-foot capacity. The sludge hopper has six compartments, each with about a one-day sludge storage capacity. Two compartments are normally used, the other four being reserved for periods when sludge hauling is not practical. The sludge is loaded out from the hopper into trailer trucks five to six days per week. The material is hauled to farmlands for use as a soil conditioner. Sludge cake can also be stored outside in emergency situations. There is a possibility that this material can be used as an animal feed and thus be sold as a valuable byproduct.

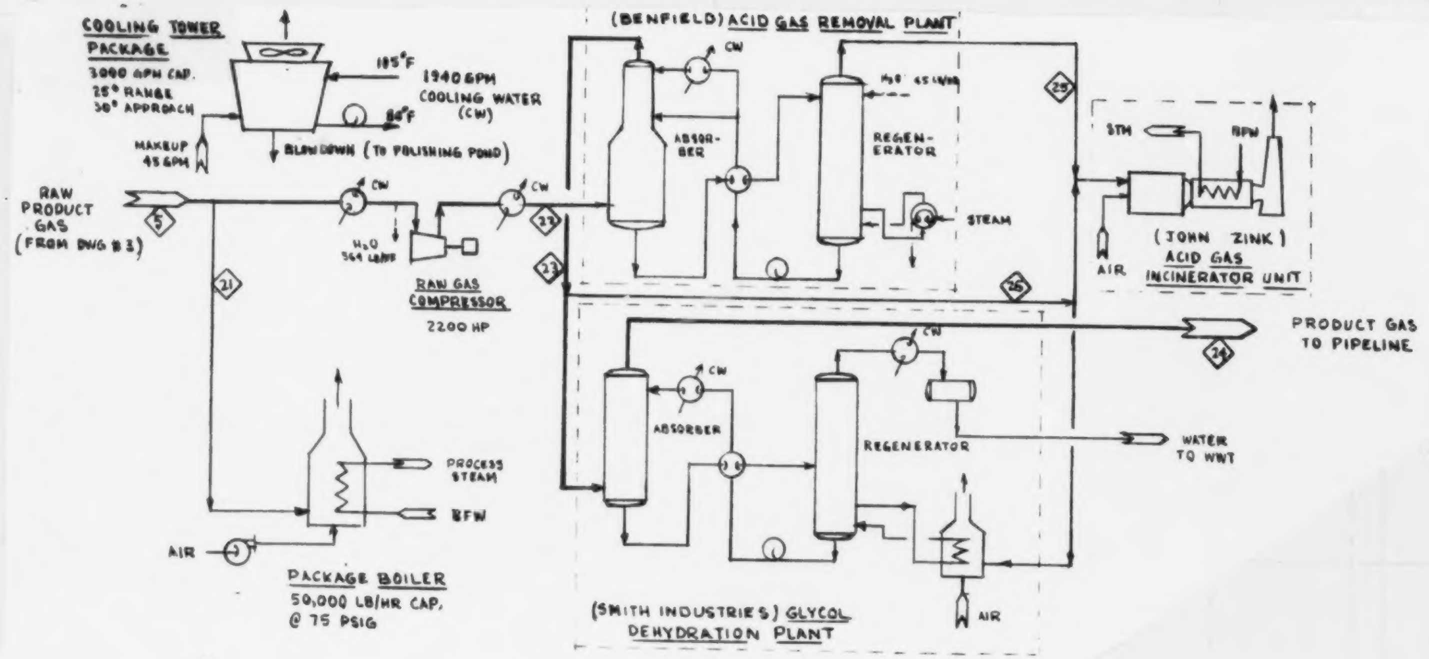
Approximately 80 percent of the centrifuge centrate is recycled to the process and the remainder goes to a 34-foot diameter primary clarifier. Solids in the centrate are collected in the bottom of the clarifier and pumped to the feed preparation section of the process. The clarifier overflow goes to a plastic-lined aeration basin where residual organics are metabolized by aerobic bacteria. The aeration basin has a capacity of 400,000 gallons, with water surface dimensions of 90 feet by 90 feet and a 10-foot side water depth. The aeration basin provides a detention time of one day. Four 25-hp floating mechanical aerators (including one installed spare) provide mixing energy and transfer dissolved oxygen to the basin contents to ensure optimum operation. The basin effluent flows to two 28-foot diameter clarifiers, each with a 10-foot side water depth and four-hour detention time. Sludge scraping mechanisms move settled sludge towards the center of the clarifier where it collects in a sump and is recycled by four 200 gpm pumps (including two installed spares) to the aeration basin (165 gpm) and to the process (20 gpm).

The clarifier overflow goes to a clay-lined polishing pond having about a 10-million-gallon capacity and a detention time of 30 days. The pond measures 495 feet by 260 feet at the water surface, with a 12-foot side water depth. The polishing pond effluent can flow by gravity via a discharge line to the nearby river or be recycled (to the process) by a 250 gpm pump for use as makeup water. About 50 percent of the effluent is assumed to be discharged during normal operation. The maximum fraction of effluent recycling would have to be determined in actual operation of the plant.

Storm runoff from 94 acres of plant process area is collected in storm sewers and routed to the polishing pond for sediment removal. Ten inches per year of runoff would add an annual average of about 50 gpm to the pond influent. The runoff from a ten-year, 24-hour storm event would fill the pond (if empty). Several hours' holdup is provided for storm runoff by keeping the pond at less than maximum water level.

Gas Cleaning

An average of 11.35 million (MM) SCFD (dry basis) of raw gas from the digesters is treated to remove carbon dioxide, hydrogen sulfide, and water vapor, upgrading the heating value to 950 Btu/SCF (dry). The gas cleaning and upgrading process is shown in Figure 19. Design processing capacity is 13.5 MM SCFD (dry). About 1.5 MM SCFD of the raw gas is burned to generate process steam.


COOLING TOWER PACKAGE
3000 GPM CAP.
25° RANGE
30° APPROACH
MAKEUP 45 GPM
105°F
1940 GPM
COOLING WATER (CW)
80°F
BLOWDOWN (TO POLISHING POND)
RAW PRODUCT GAS (FROM DWG # 3)
5
21
CW
H_2O 364 LB/HR
RAW GAS COMPRESSOR
2200 HP
22
23
PROCESS STEAM
BFW
AIR
PACKAGE BOILER
50,000 LB/HR CAP.
@ 75 PSIG
(BENFIELD) ACID GAS REMOVAL PLANT
ABSORBER
REGENERATOR
H_2O 65 LB/HR
STEAM
25
26
STM
BFW
AIR
(JOHN ZINK) ACID GAS INCINERATOR UNIT
PRODUCT GAS TO PIPELINE
24
ABSORBER
REGENERATOR
WATER TO WWT
AIR
(SMITH INDUSTRIES) GLYCOL DEHYDRATION PLANT

COMPONENT \ DESCRIPTION	5 RAW PRODUCT GAS	21 FUEL TO UTILITY BLR	22 COMPRESSED GAS	23 WET PRODUCT GAS	24 DRY PRODUCT GAS	25 ACID GAS	26 CONSUMED FUEL
FLOW, (DRY) SCFM (60°F)	8,910	1,025	7,885	5,045	4,870	2,839	175
LB/HR	37,750	4,350	33,400	13,700	13,225	19,700	475
TEMP, °F	177	177	200	122	~130	122	122
PRESS., PSIA	27	27	325	323	320	19.7	323
COMPOSITION, %V (DRY)							
CH_4	60.00	60.00	60.00	93.56	93.56	0.44	93.56
CO_2	38.90	38.90	38.90	4.88	4.88	99.27	4.88
H_2	1.00	1.00	1.00	1.56	1.56	0.01	1.56
H_2S	0.10	0.10	0.10	(15 PPMV)	(15 PPMV)	0.28	(15 PPMV)
MOISTURE, %V (WET)	5.83	5.83	3.55	0.45	(200 PPMV)	9.07	0.45
HHV (BTU/DRY SCF)	610	610	610	950	950	6.3	950

Figure 19. Straw/manure to gas, gas cleaning section.

The raw gas from the mixing gas blower output is compressed from 27 psia to 325 psia for treatment in a Benfield hot potassium carbonate absorption system.

The Benfield plant (proprietary process) reduces the sulfur content of the gas from 0.1 percent by volume to 15 ppmv hydrogen sulfide and reduces the carbon dioxide content to 4.88 percent. At the same time, the heating value of the digester gas is upgraded from 610 to 950 Btu/SCF on a dry basis.

In the Benfield absorber, the descending lean potassium carbonate solution physically absorbs the carbon dioxide and hydrogen sulfide from the raw gas as it rises through the column. The rich potassium carbonate solution is regenerated in a stripping column. The acid gas from the stripping column contains primarily carbon dioxide and water vapor with small quantities of hydrogen sulfide and methane.

The acid gas stream is diverted to an incinerator/waste heat recovery system in which the acid gas (170,000 SCFH gas containing 0.175 percent H_2S) is incinerated using about 10,000 SCFH of clean product gas as fuel. The acid gas incinerator is equipped with a waste heat boiler which recovers energy from the hot gas by generating about 6000 lb/hr of 50 psig steam. The acid contains too much hydrogen sulfide to be vented directly to the atmosphere.

The wet product gas from the Benfield plant is fed into the absorber section of a glycol dehydration system in which the moisture content of the product gas is reduced to about 200 ppmv. The spent glycol (dilute glycol) is regenerated by heating and recirculated to the absorber.

Seven million SCFD of clean product gas at about 320 psia is piped three miles to the nearest gas pipeline.

Auxiliary Facilities

Utility Boiler--

A package boiler system generates 50,000 lb/hr of steam at 75 psig for process use (digesters and reboiler heating). The package also includes a 340 gph boiler feedwater treatment system consisting of a media filter and a softener.

River Water Supply--

River water is used for process makeup water. Figure 20 shows the plant water balance. A 310-gpm-capacity pump transfers water from the intake pumphouse at the river to a 1,200,000-gallon-capacity, clay-lined holding basin which stores a three-day supply for maximum makeup demand. The holding basin measures 200 feet by 100 feet at the water surface with a 10-foot side water depth. Total makeup averages about 200 gpm. Makeup water is pumped to the process as needed.

Potable Water Supply--

Potable water is pumped at 16 gpm from one of two shallow wells on the site into a storage tank. The storage tank provides a two-day water supply capacity (54,000 gallons) at 20 gpm maximum demand. Boiler feedwater makeup is also supplied from this tank. The tank contents are chlorinated at two mg/l dosage.

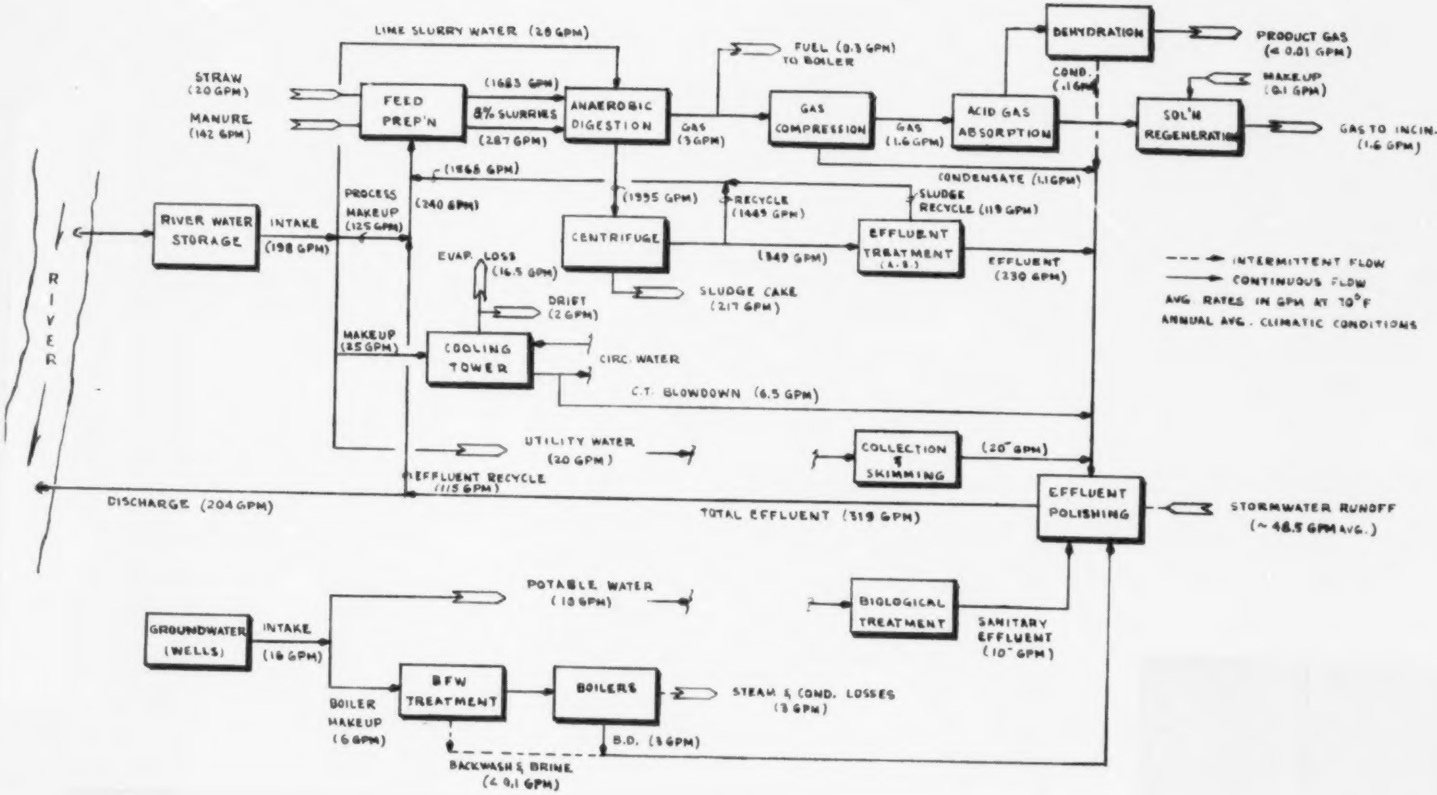

LIME SLURRY WATER (28 GPM)
STRAW (20 GPM)
MANURE (142 GPM)
FEED PREP'N
(1683 GPM)
8% SLURRIES
(287 GPM)
ANAEROBIC DIGESTION
GAS (3 GPM)
FUEL (0.3 GPM) TO BOILER
GAS COMPRESSION
GAS (1.6 GPM)
ACID GAS ABSORPTION
DEHYDRATION
PRODUCT GAS (< 0.01 GPM)
COND. (.1 GPM)
MAKEUP (0.1 GPM)
SOL'N REGENERATION
GAS TO INCIN. (1.6 GPM)
CONDENSATE (1.1 GPM)
(1868 GPM)
(240 GPM)
(1995 GPM)
RECYCLE (1469 GPM)
SLUDGE RECYCLE (119 GPM)
RIVER WATER STORAGE
INTAKE (198 GPM)
PROCESS MAKEUP (125 GPM)
CENTRIFUGE
(349 GPM)
EFFLUENT TREATMENT (A.S.)
EFFLUENT (230 GPM)
SLUDGE CAKE (217 GPM)
EVAP. LOSS (16.5 GPM)
DRIFT (2 GPM)
MAKEUP (85 GPM)
COOLING TOWER
CIRC. WATER
C.T. BLOWDOWN (6.5 GPM)
INTERMITTENT FLOW
CONTINUOUS FLOW
AVG. RATES IN GPM AT 70°F
ANNUAL AVG. CLIMATIC CONDITIONS
R I V E R
UTILITY WATER (20 GPM)
COLLECTION & SKIMMING
(20 GPM)
EFFLUENT RECYCLE (115 GPM)
DISCHARGE (204 GPM)
TOTAL EFFLUENT (319 GPM)
EFFLUENT POLISHING
STORMWATER RUNOFF (~ 48.5 GPM AVG.)
POTABLE WATER (10 GPM)
BIOLOGICAL TREATMENT
SANITARY EFFLUENT (10 GPM)
GROUNDWATER (WELLS)
INTAKE (16 GPM)
BFW TREATMENT
BOILERS
STEAM & COND. LOSSES (3 GPM)
BOILER MAKEUP (6 GPM)
B.D. (3 GPM)
BACKWASH & BRINE (< 0.1 GPM)

Figure 20. Straw/manure to gas, simplified plant water balance.

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Cooling Water System--
A recirculating water system supplies cooling water to exchangers in the gas cleaning section. About 1940 gpm circulation is provided by pumping water from the cooling tower basin. A two-cell tower with two 8-foot diameter, 25 hp fans has a 3000 gpm rating at a 25°F cooling range with a 30°F approach to the wet bulb temperature. Average heat dissipation is about 25 million Btu/hr. Makeup water (25 gpm) is supplied to the tower from the river water storage pond. Cooling tower blowdown is sent to the polishing pond.

Sanitary Waste Treatment--
Sanitary wastewater is collected and treated in a package biological treatment unit. The treated effluent is disinfected before being sent to the polishing pond.

Flare System--
All pressure vessels and equipment are connected to the plant relief and blowdown system. A 12-inch diameter, 100-foot high elevated flare is capable of burning all of the product gas.

Other--
Other facilities, excluding buildings and civil structures, include the electrical distribution system, the drainage system, the fire protection system, and the compressed air system.

Plant Thermal Balance

The overall thermal efficiency of the plant is estimated on a fuel heat content basis. Energy inputs are the heat values of the manure and wheat straw and the electric power consumed. The auxiliary fuel consumed (natural gas, diesel and gasoline fuels) is omitted from the balance.

Table 51 summarizes major factors in the thermal balance. Electric power is converted to fuel equivalent basis by assuming a 33-percent conversion efficiency for a natural-gas-fired power plant.

About 40 percent of the feedstock heat value is converted to fuel energy in the form of raw product gas. Internal gas consumption reduces the product gas output to 34 percent of the feedstock heat value and 31.9 percent overall output. Most of the input energy is lost as "unconverted" residue, a consequence of the digestion process.

BIOGAS PLANT COSTS

A conceptual estimate was made for the straw-and-manure-to-gas plant located on the hypothetical 140-acre site in the midwest. Table 52 summarizes the major capital cost elements. Mechanical equipment and piping are the largest direct field cost elements.

Pollution control equipment costs are a relatively low percentage (4.5) of the field costs — most of this is for wastewater cleanup. The total capital cost of $85.2 million represents an investment of about $12,800/MM Btu/day

TABLE 51. BIOGAS PLANT THERMAL BALANCE FACTORS

Factors	MM Btu/hr	MW	% of Input
Input			
Straw (input)	712.4	208.7	81.8
Manure (input)	102.1	19.9	11.7
Electric power (7300 hp ÷ 0.33 conversion effic.)	56.3	16.5	6.5
Total	870.8	255.1	100.0
Outputs and Direct Consumption			
Digester gas product (8910 SCFM at 610 Btu/SCF)	326.1	95.5	37.4
(-) gas used in digester heating	(16.4)	(4.8)	(1.9)
(-) gas used in gas cleaning	(20.0)	(5.9)	(2.3)
(-) gas used for building heating	(1.1)	(0.3)	(0.1)
(-) gas used for incinerator fuel	(9.9)	(2.9)	(1.1)
(-) heat in acid gas stream incinerated	(1.1)	(0.3)	(0.1)
Dry product gas to pipeline	277.6	82.3	31.9
Losses (balance)	593.2	173.8	68.1
(dissipated as heat, rejected as nonconverted residue)			

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TABLE 52. STRAW/MANURE-TO GAS CAPITAL COSTS

Element	$1,000,000's
Site and Yard	1.5
Civil/Structural	7.2
Process Mechanical Equipment	16.8
Pollution Control Equipment	1.9
Piping and Instrumentation	13.0
Electrical	1.6
DIRECT FIELD COST	42.0
Indirect Field Cost	7.0
TOTAL FIELD COST	49.0
Engineering Services	5.9
	54.9
Allowance for Uncertainty	11.0
TOTAL CONSTRUCTION COST	65.9
Land	0.6
Other Owner Costs	1.3
Startup	6.6
Allowance for Funds During Construction	6.7
FIXED CAPITAL INVESTMENT	81.1
Working Capital	4.1
TOTAL CAPITAL COST First Quarter 1978, Price and Wage Levels	85.2

of gas output. This is, as expected, quite a bit higher than estimated investments for large high-Btu gasification plants. For comparison, a 1975 Parsons report (4) indicated a similar investment at a low gas production rate for a municipal refuse-to-SNG plant by PUROX^R pyrolysis and methanation — $80 million at 7.6 MMM Btu/day. In contrast, SRI (11) estimates an investment of about $8350/MM Btu/day for a 5.1 MM SCFD SNG plant for anaerobic digestion of cattle manure.

Annual operating costs are summarized in Table 53. The plant operation is labor intensive and has a large fraction of high maintenance equipment. Electric power consumption is high and also adds significantly to the operating costs. Table 54 presents annualized costs for capital, operation, and feedstock. The annualized capital cost is based on 100-percent debt financing at nine percent interest, the simplified basis used in Section 3 also. As noted earlier, no credit is taken for the digester solids residue. If this material could be used as animal feed, a significant byproduct credit would offset the high annual operating costs.

On this basis, however, both the annual capital and the annual operating costs exceed the total feedstock costs. These base feedstock prices represent about $1.70/MSCF ($1.80/MM Btu) of gas produced, or 20 percent of the total production cost of gas.

Figure 21 illustrates the sensitivity of gas cost to feedstock prices on both a utility and private financing basis. These gas costs are about $7.68 and $10.63/MM Btu, respectively, at zero straw and manure costs. On a feedstock/Btu basis, each $1/MM Btu of straw and manure cost adds about $2.50/MM Btu to the gas cost. Feedstock costs are quite important, especially in view of the high cost of gas production as estimated here.

BIOGAS ENVIRONMENTAL ASSESSMENT

Impacts will occur from wheat straw and manure collection activities as well as from construction and operation of the biogas plant. General environmental impacts for the hypothetical plant located in the midwest are described below.

Feedstock Procurement Impacts

Removal of about 330,000 tons per year each of wheat straw and manure from the land will cause certain environmental impacts away from the plant site itself. Feedstock procurement impacts are discussed in general. Much more detailed site information would be needed to accurately assess impacts in a specific locale — as would be done in an environmental impact report for a project such as hypothesized here.

Wheat Straw--

Residue removal from soils has the potential for causing the largest adverse impact resulting from feedstock procurement. Relatively large land areas are affected by residue collection because of low field density of wheat straw. Soil erosion is the principal concern in this geographic region. Soil related impacts are discussed below.

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TABLE 53. ANNUAL OPERATING AND MAINTENANCE COSTS* — STRAW/MANURE TO GAS

Element	$1,000,000's
Supplies	0.6
Utilities	1.2
Operating Personnel	1.4
Maintenance Labor and Materials	1.0
Supervision	0.3
Administration and Overhead	0.3
Local Taxes and Insurance	1.7
TOTAL ESTIMATED ANNUAL OPERATING COST First Quarter 1978, Price and Wage Levels	6.5

*Excluding straw/manure feedstock.

TABLE 54. ANNUALIZED COST OF GAS PRODUCTION

Element	$1,000's	$/MSCF (net)	$/MM Btu (net)
Annualized Capital Cost (9%)	9,264	4.02	4.23
Annual Operating Cost	6,500	2.82	2.97
Annual Straw Cost (Base: $10/ton)	3,285	1.43	1.50
Annual Manure Cost (Base: $2/ton)	657	0.28	0.30
TOTAL ANNUALIZED COST	19,706	8.55	9.00

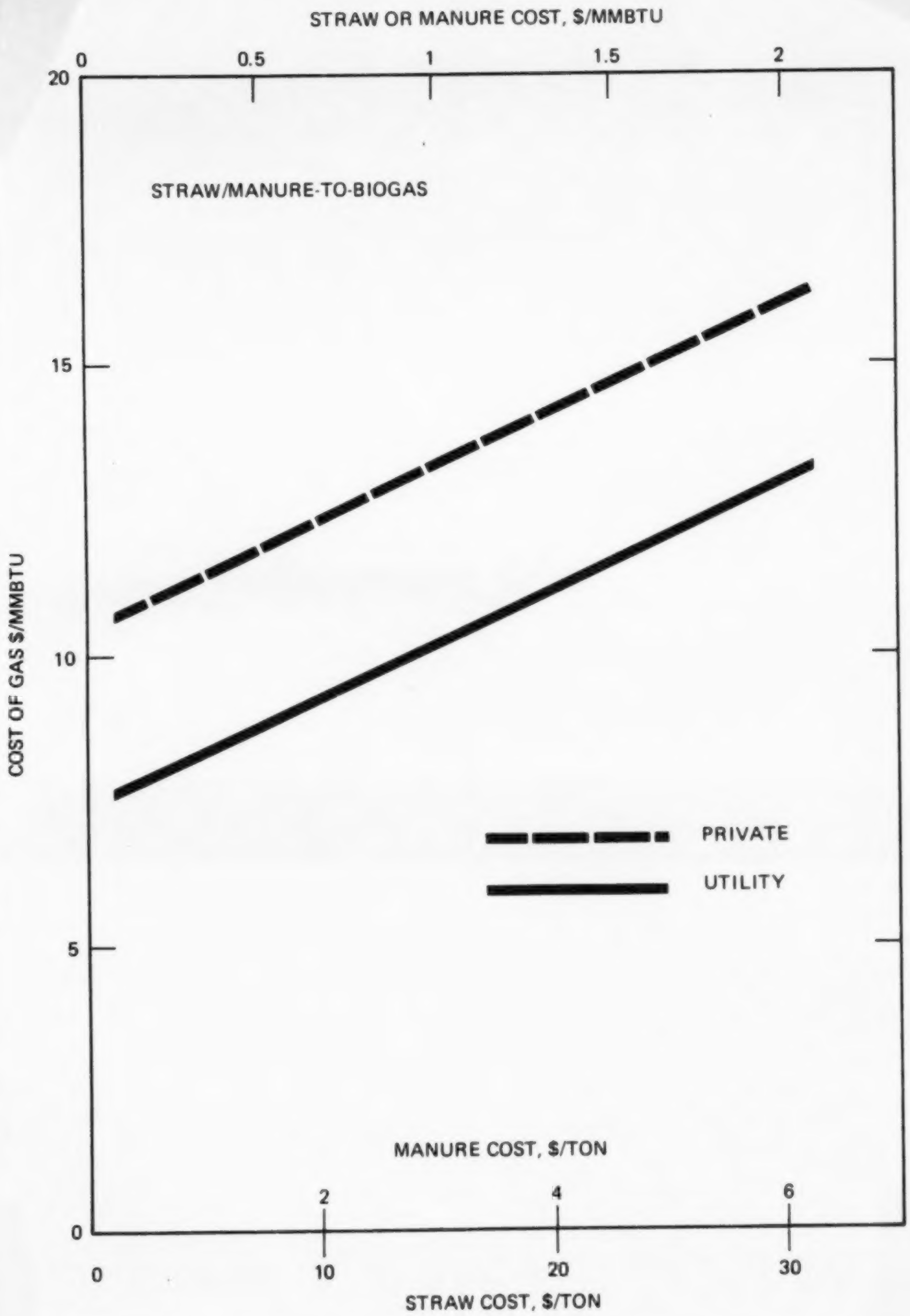

Figure 21. Effect of straw/manure cost and cost of gas with both private and utility financing.

Erosion--Moderate to strong surface winds are common in the Great Plains. Wind velocity in the vicinity of the site is highest in March and April, and soil blowing is a serious problem during dry and windy periods in spring. Compounding the problem is the fact that a good proportion of local soils are coarse-textured. Whenever windspeed exceeds 11 to 13 mph, the unprotected fine, loose, and dry soils with a smooth and bare surface blow freely. USDA has estimated 35 million acres of Great Plains cropland is severely erodible. From one to 16 million acres with a 40-year average of about five million acres are damaged annually in the region (33).

Wheat is sown on a good proportion of soils that are sands, loamy sands, and sandy loams. Unprotected, they may lose as much as 180 tonnes/ha/yr of surface soil (30). The resulting damage to the environment includes deterioration in soil fertility (34), air pollution, loss of visibility, injury to human and animal health, damage to equipment and machinery, traffic hazards, reduced seedling survival, poor yield and low quality of horticultural crops, and increased incidence of plant diseases.

Present technology for wind erosion control requires maintenance of a vegetative cover on erodible soils as one of the basic principles. In the past, it has been assumed that approximately one-half of crop residues may be removed from soils without serious consequences from wind erosion. However, recent research data have shown that this may not be true in all cases. Skidmore and Siddoway (30) undertook an investigation to determine the quantity of crop residue that may be removed from soils in the Great Plains without exposing the soils to degradation by wind erosion. Their data demonstrated that the highly erosive soils (Wind Erodibility Group 1) would require from 1120 to 3300 kg/ha (2944 lb/acre) of flat wheat straw depending on the climatic factor. Based on an average U.S. yield of all wheat per harvested hectare at 2000 kg (1784 pounds) and straw-grain ratio of 1.7, the estimated straw yield would be approximately 3400 kg/ha, or 3033 lb/acre. Therefore, one-third to virtually all wheat straw would be needed for acceptable erosion control of soils in the wind erodibility group.

Skidmore and Siddoway also calculated straw requirements of soils in Pratt County, Kansas (30). Using local wheat straw yield of 2800 kg/ha (2498 lb/acre), they concluded that the loamy fine sands and fine sandy loam soils will all straw removed would probably lose more than 100 tonnes/ha/yr (44.6 tons/acre/yr). Even the fine-textured soils would lose more than 50 tonnes/ha/yr (22.3 tons/acre/yr). If all straw were left on the soil, even the highly erodible, coarse-textured soils should not erode. If half the straw were left and maintained in upright standing position, the finer-textured soils should be adequately protected.

If field width were decreased, more wheat straw could be removed. For example, with a decrease in field width from 300 (984 feet) to 60 m (197 feet), the protective straw requirement would decrease from 3140 to 2910 kg/ha (2801 to 2596 lb/acre) on highly-erodible soils. This decrease is even more pronounced on fine-textured, less-erodible soils. Thus, on a wide field with no strip crops or other barriers, the wind erosion hazard is more pronounced than on well-managed, small-width fields. Wind breaks and different combinations of trees, shrubs, and tall growing crops (corn, sorghum, sudangrass, sunflowers, etc.) would likewise decrease straw requirement for wind erosion control.

Crop residue is also essential for protection of soils against water erosion, especially during summer thunderstorms which are sometimes accompanied by high winds, large hail, and heavy downpour. They last only a short time, but cause sheet erosion on bare and loose soils.

Great care will be needed in management of wheat straw procurement activities to protect the affected soils from serious wind and water erosion. This will mean that, in some areas, residue collection will not be possible; in some, partial collection will be practiced; and in others, full collection may be possible on a rotational basis. Since the plant's annual requirements are small compared to the total crop residue produced in the area, significant damage should be avoidable by selective collection practices augmented by increased use of erosion control techniques. Procurement management activities, if extensive, could have a negative economic impact on the plant in the form of a higher cost of delivered feedstock.

Fertility--The average U.S. wheat straw yield amounts to 3400 kg/ha/yr. This is equivalent to an addition of about 22 kg of nitrogen, 2.4 kg of phosphorus, and 30 kg of potassium per hectare to the soil if straw is plowed into the soil. In addition, approximately 5 kg of calcium, 3 kg of magnesium, 4 kg of sulfur, 0.008 kg of copper, 0.14 kg of manganese, and 0.04 kg of zinc are added per hectare (35). Assuming no nutrient elements are lost by leaching or other causes, to the extent that straw is removed, the soil will not receive these nutrients. Decreased soil fertility by residue removal will be partly offset by using digested sludge from the conversion plant on the croplands in place of decomposing straw. Although the sludge cake will not be of any great value in erosion control, its organic and nutrient contents will partially make up for the losses incurred by removal of the residue. The cake material will contain nearly all of the nutrients present in the original residue less some carbonaceous matter that is converted to gas.

Over 1800 tons per stream day of digested straw and manure residue will be available for land application. Application to crop lands will take place outside the wheat growing season, so that a management program will have to be developed for distributing the material, as needed, to farmers who supply feedstock to the plant. The feedstock contractor (whose trucks also pick up sludge cake at the plant) is assumed to provide sludge residue management services. He will also need to provide sludge storage for periods in the year when application to crop land is not practiced.

In summary, there is a potential for significant loss of cropland productivity in the area by indiscriminate removal of wheat straw residue. The adverse impact can be mitigated through a careful management program in which residues are selectively collected and the impacts of collection on soil erosion and productivity are monitored carefully.

Manure

Livestock manure collection will cause relatively small environmental impacts. Virtually all of the manure supplied to the plant will be from confined feedlots where the material is readily collectible daily. Feedlot wastes are also a significant source of water pollution and often represent a disposal problem for the feedlot operators. Presently, most of this material is aged and spread on nearby farmland as a fertilizer. Collection and removal of fresh manure will be beneficial in situations where pollution problems can be lessened. Flies are often a significant problem at feedlots. To the extent that the manure is not allowed to accumulate in exposed areas, the attraction of flies will be somewhat lessened.

Relatively small areas will be affected by manure collection — the feedlots, adjacent farmland, and haul roads. Loss of soil productivity of nearby farmland which currently receives manure as fertilizer can be offset by returning some of the plant digested sludge to these lands.

Transportation

Feedstock collection will increase the transportation burden on local (county) and state roads in the vicinity of the plant. Approximately 100 truck loads per day of feedstock will be delivered to the plant. Some of the trucks will haul digested sludge on return trips, either to yarding facilities or to farmlands. Approximately two million vehicle-miles annually would be traveled in feedstock and residue hauling. Vehicle densities on active haul roads near the plant could be quite high at times, causing localized congestion. Employee traffic at shift changes would add to the problem. Away from the plant, the vehicular densities would be quite low and should not overburden the road system.

Motor fuel consumption (about 0.2 percent of plant energy output) and vehicular emissions will increase as a direct result of procurement activities. In comparison to the annual vehicle-miles expended in the collection area (about 3800 square miles), these increases will be small. In addition to vehicle pollutant emissions, some increase in fugitive dust emissions can be expected from hauling activities on farmlands and roads.

Social and Economic

Feedstock collection will create permanent employment opportunities for 30 to 50 people in the area. Farmers and feedlot operators supplying feedstock will receive income from the sale of their residues. The contractors who procure the residues will receive income from the plant itself through the sale of feedstocks delivered to the plant. Approximately four million dollars per year will be added to the local economy through feedstock procurement activities.

As a summary, Table 55 lists the general impacts expected from collection and transport of wheat straw and manure to the biogas plant.

Plant Impacts

Environmental impacts of constructing and operating the biogas plant are broken down into four categories:

- Physical/chemical
- Biological

TABLE 55. PROCUREMENT IMPACT SUMMARY — WHEAT STRAW AND MANURE

Environmental Factors	Biomass Procurement Impacts	Potential Mitigating Measures
Air Quality	Straw - minor adverse impact from vehicle combustion emissions from field collection; potential severe fugitive dust emissions from wind erosion of unstable soils	Limit or avoid collection on highly erodible soils
	Manure - minor impact from vehicle combustion emissions	
Surface Water Quality	Straw - potential degradation of water quality could result from an increase in soil erosion	Limit or avoid collection on highly erodible soils
	Manure - potential reduction of pollutant emissions from some feedlots, benefitting local stream qualities	
Groundwater Quality	Straw and manure-little direct impact	
Land Availability	Straw - abundant cropland in region; agreements with owners needed for collection of enough straw over plant operating life; some land area needed for straw yarding	
	Manure - little impact on land availability; may encourage development of large feedlots to supply manure	
Ecology and Critical Habitat	Straw - some 220,000 to perhaps 600,000 acres of land will be subjected to straw collection each year; temporary displacement of animals during collection, possible disturbance of habitats (removal of ground cover) of some small animals	

(Continued)

TABLE 55. (Continued)

Environmental Factors	Biomass Procurement Impacts	Potential Mitigating Measures
Ecology and Critical Habitat (continued)	Manure - little impact on plant and animal life	
Soils and Geology	Straw - potential for severe wind and water erosion of some soils with complete or even partial residue removal; decrease in soil fertility due to removal of nutrients in residue	Develop residue collection and management plan including soil surveys, erosion control plans, monitoring of collection activities; replenishment of nutrients by application of undigested residue from plant
	Manure - potential for some reduction of soil fertility where raw manure used as fertilizer on farmland	Replenishment of nutrients by application of undigested residue from plant
Aesthetic and Recreational Resources	Straw and manure - no discernible effect	
Community Economy	Straw and manure - about $4 million annual input to regional economy through purchase of delivered residues	
Community Population and Services	Straw and manure - little increase expected in local population and in demand for services	
Labor Availability	Straw and manure - local manpower resources are adequate to provide personnel for jobs created by procurement activities; benefit to local workforce	
Transportation	Straw and manure - small increase in traffic burden on local roads and highways; localized congestion may occur at times	

- Socioeconomic
- Aesthetic

Table 56 summarizes the physical resources committed to the operation of the conversion plant. Table 57 shows estimated annual chemical requirements.

TABLE 56. PRINCIPAL RESOURCES COMMITTED TO PLANT OPERATION

Resource Category	Quantity	Normalized Quantity (Output)*
Land	140 acres	0.5 acre/MM Btu/hr
Feedstock		
Wheat Straw	328,500 tons/yr	300.2 lb/MM Btu
Cattle Manure	328,500 tons/yr	300.2 lb/MM Btu
Auxiliary fuel	11,900 MM Btu/yr	544 Btu/MM Btu
Chemicals (Total)	6,150 tons/yr	5.6 lb/MM Btu
Electric Power	42.9 MM kWh/yr	19.6 kW/MM Btu/hr
Water	94 MM gal/yr	42.9 gal/MM Btu
Manpower (99 Employees)	198,000 manhours/hr	0.09 mh/MM Btu

*Basis: 2.1886 trillion Btu/yr net output.

The construction period (start of engineering to construction completion) is assumed to be three years. Several hundred workers will be onsite at the peak of construction. Resources such as fuel, power, water, and manpower will also be consumed during plant construction.

Physical/Chemical Emissions and Impacts--

Air Emissions--The straw-and-manure-to-gas (biogas) plant will have several types of air emissions as summarized in Table 58. Fugitive dust emissions will result from materials handling operations. Odors may emanate from manure and digested sludge handling. The incinerator and utility boiler will be sources of combustion gases and the cooling tower will exhaust water vapor and water droplets (drift). None of the sources, except the acid gas incinerator, is expected to be a major emitter of air pollutants if properly

TABLE 57. SUMMARY OF ANNUAL CHEMICAL REQUIREMENTS — STRAW AND MANURE TO GAS

Chemical	Amount Per Year
Lime	6,100 tons
Polymer	41 tons
Chlorine	2 tons
Sodium Chloride	2 tons
Sulfuric Acid	2 tons
Glycol	1.6 tons
Benfield Solution	333 gal
Lube Oil	1,000 gal
Auxiliary Fuel	
Diesel	66,000 gal
Gasoline	16,000 gal
Natural Gas	1,000 MSCF

TABLE 58. SUMMARY OF ESTIMATED AIR EMISSIONS — STRAW AND MANURE TO GAS

Emission Source	Flow Quantity	Pollutants	Emission Rate
Straw dump bin	1000 tons/day of baled straw	Fugitive dust	10 lb/day
Unbaler and hammermill crushers	62.5 tons/hr for 16 hr/day (1MMCFD air)	Fugitive dust	2 lb/day (after collector)
Straw (shredded) pneumatic conveyor	62.5 tons/hr for 16/hr day (2400 CFM)	Fugitive dust	4 lb/day (after collector)
Straw secondary crushers	44 tons/hr for 23 hr/day (1 MMCFD air)	Fugitive dust	2 lb/day (after collector)
Straw (ground) pneumatic conveyor	44 tons/hr for 23 hr/day (1600 CFM)	Fugitive dust	4 lb/day (after collector)
Baled straw storage area	30,000 tons of baled straw stored	Fugitive dust	10 lb/day
Lime storage silo	20 tons/day lime 45,000 CFD air	Fugitive dust	1 lb/day (after collector)
Manure storage area, sludge centrifuge and loadout bin	-	Odor potential	-
Glycol reboiler heater	100 SCFM (11 MM Btu/day)	NO_x* SO_x CO* HC*	5.5 lb/day 0.3 lb/day <1 lb/day <1 lb/day

(Continued)

TABLE 58. (Continued)

Emission Source	Flow Quantity	Pollutants	Emission Rate
Acid gas incinerator	5370 SCFM (230 MM Btu/day)	NO_x^*	1,933 lb/day
		SO_x	115 lb/day
		CO*	<23 lb/day
		HC*	<23 lb/day
Utility boiler stack	9750 SCFM (900 MM Btu/day)	NO_x^*	450 lb/day
		SO_x	249 lb/day
		CO*	<90 lb/day
		HC*	<90 lb/day
Cooling tower	150,000 SCFM (dry air)	Water (droplets)	970 lb/hr
		Salts	128 lb/day

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*Assumed emission factors: 0.5 lb NO_2/MM Btu, <0.1 lb CO/MM Btu, <0.1 lb HC/MM Btu

operated and controlled. Cumulatively, there will be a minor adverse effect on ambient air quality.

Handling of straw bales will not result in the release of significant amounts of dust. Straw grinding and pneumatic transport facilities are equipped with mechanical collectors (for straw) and fabric filter collectors for dust removal from vented air.

Manure handling is not expected to be a significant source of dust emissions. the material is moist and nonparticulate in nature. Its odor, however, may be objectionable to workers. Exposure of employees will be limited. A similar odor problem may occur with the digested sludge from the centrifuges (its odorous nature is not known). Enclosed areas will be ventilated and ventilation air ducted to roof vents. Both materials may attract flies and other insects. Some chemical treatment may have to be used to control insects at the dump hopper and truck loadout areas. For the most part, the manure and digested sludge will be handled in enclosed equipment or buildings.

Three combustion units in the plant will be sources of combustion product emissions. The incinerator will burn the acid gas stream from the Benfield plant because the stream will contain a concentration of hydrogen sulfide too high to be vented to the atmosphere. Incinerator flue gas will contain the sulfur as sulfur oxides — nearly one ton a day. Small amounts of nitrogen oxides, carbon monoxide, and hydrocarbons will also be emitted.

The utility boiler will burn raw product gas to produce process steam. The raw gas will contain about 1.4 lb of sulfur per million Btu of heating value. The small capacity (about 37 million Btu per hour heat input) of the boiler exempts it from current stationary new source SO_x standards. Other pollutant emissions will be low. A very small portion of the product gas will be burned to generate reboiler steam for the glycol regeneration column. The heater flue gas flow will be small and pollutant emissions low.

The cooling tower will discharge heat and water vapor (8250 lb/hr) to the atmosphere. The drift (water droplets) from the tower will contain about 20 tons per year of salts that will be deposited on the ground in the vicinity of the tower. Miscellaneous emission sources will include the emergency flare (pilots continuously burn a small amount of gas), fuel storage tank vents, mobile equipment exhausts, and combustion products from periodic testing of the auxiliary diesel generator.

The air resources area is designated as nonattainment for photochemical oxidants and CO standards. The plant will contribute small amounts (less than 100 tons/yr) of these pollutants. The overall impact of plant pollutant emissions will be a small, though adverse, effect on ambient air quality. The emissions will have no discernible effect on the climate in the vicinity of the plant.

Water Emissions--Wastewater sources are summarized in Table 59. The conversion process employs water as the biomass carrying medium. The digester throughput will be nearly 2000 gpm. With direct recycling and at least partial recycling of treated effluent, process wastewater emissions may be kept fairly low. However, digester effluent will probably contain high concentrations of organic and inorganic materials. Activated sludge treatment followed by long detention in a polishing pond is expected to reduce the biochemical oxygen demand (BOD) to a level acceptable for discharge to the river. If 50 percent of the polishing pond effluent could be recycled to the process, only about 115 gpm of digester effluent would be discharged. Principal pollutants will be BOD, suspended solids, and dissolved solids. Dissolved solids will be high because of leaching of digester solids and addition of lime and recycling (concentrating) effluent. The effluent will also contain some nitrogen and phosphorus extracted from the feed materials. Amounts which would be present in the effluent are undefined, and a large fraction of these biostimulants could be retained in the digester sludge. However, if organic and ammonia nitrogen contents of the polishing pond effluent are high, a nitrogen removal step will need to be incorporated in the effluent treatment system.

Use of a solar evaporation pond to impound all of the process effluent would be a possibility in areas of high annual net evaporation rates. A significant amount of land area would need to be added to the plant site for such a pond (about 100 acres at 20 inches net evaporation).

Other plant wastewater streams will be relatively minor sources of pollutant emissions (Table 59). All will be routed through the polishing pond before discharge or reuse. Storm runoff collected from the plant process areas (about 94 acres) will be a significant water pollutant source on an annual

TABLE 59. SUMMARY OF ESTIMATED WASTEWATER EMISSIONS — STRAW AND MANURE TO GAS

Source	Estimated Flow	Pollutants		Emission Rate
Digester Effluent (after polishing pond)	115 gpm	BOD	(80 mg/l)	100 lb/day
		TSS	(40 mg/l)	55 lb/day
		TDS	(∿10,000 mg/l)	∿13,800 lb/day
		Nitrogen	(∿50 mg/l)	∿69 lb/day
		Phosphorus	(∿10 mg/l)	∿14 lb/day
		pH		6-9
Utility Wastewater (after treatment)	20 gpm	Oil & grease	(<10 mg/l)	<2.4 lb/day
		TSS	(<30 mg/l)	<7.2 lb/day
		pH		6-9
Cooling Tower Blowdown (after settling)	6.5 gpm	TSS	(40 mg/l)	3.1 lb/day
		TDS	(5500 mg/l)	429 lb/day
		Cl_2 residual	(<.1 mg/l)	<.001 lb/day
		pH		6-9
Boiler Blowdown (after settling)	3 gpm	TSS	(50 mg/l)	1.8 lb/day
		TDS	(300 mg/l)	10.8 lb/day
		pH		6-9
Sanitary Wastewater (after treatment)	10 gpm	BOD	(<35 mg/l)	<4.2 lb/day
		TSS	(<35 mg/l)	<4.2 lb/day
		pH		6-9
Storm Runoff (after settling)	48.5 gpm annual avg	BOD	(<10 mg/l)	<5.8 lb/day
		TSS	(<50 mg/l)	<29 lb/day
		pH		6-9

basis. During heavy rainfall, much of the stormwater will be discharged after passing through the polishing pond, since complete inpoundment is not provided. Discharged stormwater will contain some suspended solids carried over from the pond. However, runoff collected in the polishing pond will tend to dilute the process effluent, decreasing the total effluent loading to the river. The runoff itself will carry silt into the pond. Periodic cleanout of accumulated solids will be needed.

Increased recycling might be practiced during wet weather periods, reducing the river water intake demand.

Plant effluent discharges into the receiving water will have adverse, though small, effects on the river water quality. Mass emission rates of BOD, suspended solids, and other pollutants will be low compared with total mass flow of such pollutants in the river. Increases in pollutant concentrations in the river are unlikely to be measurable. Nevertheless, the potential value of the river as a surface water supply will be decreased slightly. Additions of oxygen demand, biostimulants, and total solids will not be beneficial to stream quality. The plant water demand of about 200 gpm of river water and about 16 gpm of well water will also reduce available water resources by a small amount.

Solid Waste Emissions--The plant will have two main sources of solid waste (Table 60). The largest is the residue of undigested manure and wheat straw in the form of a centrifuge cake. About 534 tons per day of solids will be recovered as waste solids from the digesters. The material still contains many of the nutrients from the feedstock materials that would be beneficial for soil productivity. Regular hauling of the residues to farmlands for use as a soil amendment will result in an overall beneficial effect on the environment — at least compared with the awkward alternatives. If it were feasible, the use of this material as an animal feed would be an attractive solution.

The large quantities will make it nearly impractical to provide for onsite disposal of sludge in landfills. The wet sludge would be susceptible to erosion and pollution of surface and groundwaters if deposited in large exposed piles on the land. It could also attract flies and other pests.

Interim storage (e.g., during winter months) will be needed for periods when land application is not possible. At interim storage sites, there will still exist the potential for contaminated leachate and runoff. Surface and groundwaters need to be protected from contact with contaminated water. Improper handling and disposal of the large quantity of residue offer potential for significant damage to water resources.

Plant general trash and garbage will be collected and buried on site in a small sanitary landfill. About 10 acre-feet of such waste will be generated over the life of the plant. Disposal by landfilling will cause relatively little impact on the physical/chemical environment.

Soils and Geology--The biogas plant will be constructed on a hypothetical site currently used as cropland. The area altered by plant construction and operation will be about 140 acres. Some additional offsite land will be disturbed

TABLE 60. SOLID WASTE DISPOSAL SUMMARY — STRAW AND MANURE TO GAS

Source	Estimated Quantity	Potential Pollutants	Disposal
Centrifuge Sludge Cake (Digester Solids)	1,840 tons/day wet, 534 tons/day dry solids	Organic materials,* calcium, nitrogen, phosphorus, potassium, sulfur	About 13,000 tons per week hauled to farm lands for disposal
Plant Trash and Garbage	300 lb/day	Decomposable waste, some oily material	About 400 cu ft per week collected and buried onsite
Miscellaneous Scrap Materials, Basin Cleanouts	Intermittent (no estimate of quantity)	Organics, suspended solids	Collected periodically and buried onsite

*Potential pesticide/insecticide residues if such materials were present in the straw or manure feedstocks.

by construction of the access road, the connector gas pipeline, and the imported power transmission facilities. In the main plant construction, earthwork will include removal of soil cover, leveling most of the area, and some excavation for basins and foundations. Much of the area will be permanently covered with new surface materials. In the undeveloped or buffer portion (within the fence line), changes in the land surface will be less drastic.

The changes in the land surface will be substantial on the site but will be minor overall, compared with the large amount of land area in the region with similar characteristics.

Biological Impacts--
During plant construction, native vegetation (mainly grasses) and wildlife on those portions of the 140-acre site not now farmed will be removed or disturbed. Winter wheat will no longer be grown as a cash crop on a portion of the site. Wildlife in nearby habitats will be subjected to human presence and construction noise. Movement of animals across the site will be restricted by the boundary line fence. During the plant operating phase, most of the wildlife would probably return to similar habitats in the vicinity of the site but avoid the heavily traveled access road. All of the vegetation and wildlife species on the site are well represented in nearby areas of the region; therefore, the destruction of onsite vegetation and the displacement of wildlife will not have a significant overall effect on the biological life in the region.

Secondary effects resulting from construction activities will be limited to temporary and localized damage offsite. Some vegetation may be damaged by fugitive emissions or by erosion resulting from changes in drainage ways. Construction site runoff may temporarily increase sediment loading in surface waters and cause harm to aquatic species.

The effect of the operating plant air emissions on biological life should be small. The sulfur oxide (SO_x) concentration in the incinerator stack discharge will be high (nearly 1500 ppm). Theoretically, some damage to the leaves of SO_x sensitive species (alfalfa, wheat grass) could occur if plume concentrations were forced to the ground by adverse meteorological conditions. Normally, the plume will be dispersed sufficiently so that no significant impact on vegetation is anticipated.

The small quantity of salt from the cooling-tower drift is not expected to cause plant damage offsite. Landscape plants near the tower might be affected. the uncertainty in the quality of effluent from the plant makes it difficult to assess the magnitude of the secondary impacts.

Wastewater emissions could cause a minor degradation of river water quality which, during low river flow periods, could stress aquatic plants and animals. Nitrogen and phosphorus in the plant effluent may stimulate undesirable plant growth, and ammonia concentrations may become high enough to affect sensitive organisms. Generally, significant damage would be limited to a relatively small mixing zone at the point of discharge into the river.

Smaller plant and animal organisms suspended in the intake water may be damaged or destroyed in the plant water systems. Intake screens will prevent the passage of most large aquatic animals. Only a very small fraction of the biological life in the river will be affected by the intake system.

Aesthetic Impacts--

The hypothetical plant site is not considered to be in an area of high visual quality although the farmland setting near a river does possess aesthetic characteristics that will be altered by construction of the plant. The visual appearance of the plant will contrast sharply with the rural surroundings. As approached from the access road, a mix of shapes will be evident — ranging from the "chemical plant" impression of the gas cleaning, utilities, and digester sections on the right to the more farm-like cluster of buildings, bins, and bales of straw further to the left. The foreground will be relatively open and uncluttered by structures. The major plant structures (digesters, feed preparation buildings, and straw storage) will be fairly low and broad (massive) in appearance but will not be noticeable from any great distance, even in nearly level terrain. Taller structures such as the flare, boiler stack, and Benfield columns will be visible but not dominating because of their slenderness. One general impression residents and casual observers might receive could be that the plant is vaguely displeasing because of its overall size and the unattractive collection of shapes. Its overall appearance, however, will not be totally foreign to this largely agricultural economy. Landscaping the plant boundary with shrubs and trees would provide a screen and help to mitigate the negative aesthetic effects.

Social and Economic Impacts--
Construction and operation of the conversion plant will be of significant economic benefit to the community. A significant fraction of the $85 million capital investment will be spent locally for equipment, materials, and construction labor. Temporary jobs for several hundred construction workers will be created. The plant will provide permanent employment for nearly one hundred people; most will be recruited locally. Increased spending in nearby towns will result, and the industrial taxes will provide additional revenue to offset the demand, at least partially, for additional community services.

Manpower resources in the area are abundant and range from unskilled through highly skilled workers. Very little increase in local population will result from the construction or operation of this facility, and the demand for new community services for workers and their families should be small. The plant itself will produce enough fuel to generate about 25 MW of power. Employment, spending, and taxes are positive impacts that will be produced by this facility.

Table 61 presents a summary of the principal environmental impacts anticipated from construction and operation of the biogas plant.

TABLE 61. SUMMARY ENVIRONMENTAL MATRIX — STRAW AND MANURE TO GAS

Environmental Factors	Effect of Plant Construction and Operation	Potential Mitigating Measures
Climatology and Meteorology	No discernable impact from plant construction or operation	
Air Quality	Potential localized impact of fugitive dust from construction; minor adverse impact from plant operation	
Surface Water Availability	Requires about 40 gal/1000 SCF product gas; small adverse impact on water resources	Potential for increasing reuse
Surface Water Quality	Small adverse impact on quality; potential for emission of biostimulants (and nitrogen phosphorus)	Experimental work needed to assess potential problems; include nitrogen removal step or use solar evaporation pond
Groundwater Availability	Requires about 3 gal/1000 SCF product; minor adverse effect on water resources	
Groundwater Quality	Little potential for degradation, ponds and basins lined; proper management of landfill site required	
Land Availability	Requires about 140 acres of land; no significant impact	Careful siting to avoid sensitive areas
Regional Ecology and Critical Habitat	About 140 acres of vegetation (mainly grasses and wheat) removed and associated wildlife displaced during construction; minor adverse direct impact; small indirect impacts on vegetation and aquatic species	Careful siting to avoid critical wildlife habitats and rare or endangered biological species

(Continued)

TABLE 61. (Continued)

Environmental Factors	Effect of Plant Construction and Operation	Potential Mitigating Measures
Aesthetic Resources	Small to moderate adverse impact-appearance conflicts with farmland surroundings	Plant design, layout and landscaping
Historical, Archaelogical Resources	Insignificant impact	Siting surveys to protect cultural resources
Community Economy	Substantial benefit from construction and operation expenditures in local communities; broadened tax base	
Community Population and Services	Small increase in local population and residential services; little adverse impact on community resources	Plant to support community in expanding services, if necessary
Labor Availability	Requirements for several hundred construction and about 100 operation personnel; local manpower resources adequate	Plant to train unskilled workers as necessary
Power Availability	Requires about 5 MW (~ 18 kWh/1000 SCF) of electric power for plant operation; current generating capacity adequate	Plant could generate required power with raw gas as fuel
Transportation Availability	Requirement for construction of access road and small product gas pipelines; small adverse impact on environment from new transport corridors	Careful selection of corridors to minimize impacts on land use, ecology, and water resources

COAL GASIFICATION PLANT SITE DESCRIPTION

The hypothetical site for the coal-to-synthetic pipeline gas plant is virtually the same in character as the biogas plant site. The 440-acre fenced tract is assumed to be a relatively flat rural location currently in agricultural land use. An additional 440-acre buffer zone is assumed to surround the fenced site. All topographic, climatic, hydrologic, biologic, and demographic conditions are similar to those of the biogas plant site.

The site is in Seismic Zone 1. The air quality region is currently a nonattainment area for photochemical oxidants and carbon monoxide. Potential costs of emission offsets were not considered in this scenario.

The plant owner is assumed to construct a river water intake system and a discharge pipeline, an all-weather access road and a rail spur to the plant, and a three-mile long, 28-inch diameter gas connector pipeline to an interstate natural gas line. The product is supplied to residential, commercial, industrial, and utility consumers in the midwest region. Western coal is received by unit train, and residual ash materials are returned by rail to the coal mine for burial.

COAL PROCUREMENT

The coal gasification plant annually consumes about 6.7 million tons of low sulfur western coal. In this scenario, it is assumed that the coal is supplied by a single strip mine located in a western state. The coal is shipped by unit train to the plant located in the south central area of a midwestern state (Kansas, Iowa, Nebraska). Coal procurement is briefly described to allow comparison with the biomass procurement scenario.

In the county where the mine site exists, there are more than five billion tons of reserves at leasehold involving about 60,000 acres of land surface. At full production, it is anticipated that more than 120 million tons per year of coal will be produced from the 12 to 15 mines in the county. The typical mine will produce more than enough coal for the conversion plant's needs. Most of the coal is sestined for the steam generating utility market.

The hypothetical mine is on a 4000-plus-acre federal leasehold. Production will average between nine and ten million tons per year over its 35-year life. The leasehold was formerly used for grazing and as cropland, and the terrain is characterized as gently rolling.

The coal bed ranges in thickness from 70 to 90 feet and the overburden ranges from 30 to 260 feet in thickness. An area surface mining method is employed in sequentially mining a series of rectangular units. A rectangular pit the width of a unit is excavated in a series of benches to the coal bed and the coal is then excavated in benches. Overburden removed from the next contiguous unit is backfilled in the previous pit when sufficient volume exists for backfilling to start.

In developing a unit, wheeled scrapers remove and stockpile the topsoil. Earth-moving equipment prepares a smooth bench for drilling and blasting.

After shooting, electric shovels on the bench excavate the overburden and load it on end-dump trucks for hauling to the previous pit. The truck-shovel method allows continuous replacement of overburden and reclamation of mined-out areas. The coal bed is also mined in benches by shooting (where necessary), excavating with electric shovels (or wheeled reclaimers), and hauling with bottom-dump trucks to the preparation plant.

The ROM coal is delivered to the dump at the preparation area and reduced to minus three-inch by primary and secondary crushing. Crushed coal is transported by enclosed belt conveyor to the 15,000-ton-capacity storage silos for carloading. Nominally two 100- to 120-car unit trains (100-ton-capacity hopper cars) will be shipped per day to the conversion plant. The moving cars are floodloaded from the bottom of the silos at a rate of 2500 tons per hour. A dust suppression chemical is sprayed on the coal surface layer to reduce coal loss during transport. The trains proceed from the rail spur to the main line (common carrier) crossing the southern part of the leasehold. The round trip averages two days (approximately 1600 miles). The mine operator accepts ash from the conversion plant for backfill in stripped portions of the mine.

The reclamation of the disturbed acreage (average of less than 100 acres per year) is aimed at returning the land to its prior use with gently rolling topography similar to its original form. Vegetation established on the topsoil-covered, backfilled spoils is intended primarily for livestock grazing. Forage production has increased over the former natural productivity of forage species.

COAL GASIFICATION PROCESS DESCRIPTION — STEAM-OXYGEN HYGAS

The coal gasification facility described in this section is based upon the use of the HYGAS^{R} process developed by the Institute of Gas Technology. The HYGAS process is considered one of the promising second-generation gasification processes. The facility is designed to convert approximately 6.7 million tons per year of western coal into synthetic pipeline gas (SPG). Low sulfur western coal is shipped to the plant by dedicated unit trains on a contract dollars-per-ton-delivered basis.

The processing steps are such that the gas produced is interchangeable with natural gas and has a higher heating value of approximately 915 Btu/SCF. The design capacity of the plant is 250 billion Btu per day of SPG (about 274 MMSCFD).

Design Bases

The conceptual plant process design presented in this section is based upon the design work performed by C.F. Braun & Co. for the Joint ERDA-AGA Coal Gasification Program with only minor balance-of-plant (nonprocess) modifications to reflect a different hypothetical plant site.

The specific reference material (6) used in this evaluation is:

> "Factored Estimates for Western Coal Commercial Concepts," prepared by C. F. Braun & Co. for the United States Energy Research and Development Administration and the American Gas Association under Contract No. E(49-18)-2240 March 1, 1976.

Table 62 presents the composition of the assumed coal feedstock for the plant.

Table 63 presents the general design bases assumed for the conceptual plant.

Table 64 presents the overall summary material balance for the HYGAS process.

The process descriptions, which follow, describe the major process facilities depicted on the simplified block flow diagram, Figure 22. Table 65 presents the compositions of the major process streams identified on the block flow diagram. Additional process details can be found in References 5 and 6.

Figure 23 indicates the general layout of the plant at a hypothetical site.

Coal Handling and Preparation

Minus three-inch raw coal enters the plant by unit train from the mine. The 100-ton capacity cars pass through a car dump station from which the coal is transferred by belt conveyor to the live storage pile stackers.

The live storage piles have a 14-day capacity. A 60-day dead storage pile (1.23 million tons) is also provided. A bucketwheel reclaimer takes coal from the pile and sends it by conveyor to the preparation areas. A venturi scrubbing system is provided at the coal preparation facilities to control fugitive dust emissions from handling the dry coal. The process coal is wet-ground in a rod mill, since the coal will eventually be fed to the gasifiers in a water slurry. The boilers and superheaters in the steam and power system contain their own pulverizing equipment. Design consumption is about 2300 tons per day.

Slurry Feed Preheating

Ground coal in water slurry is pumped to an agitated tank containing eight hours intermediate storage. From this tank the coal-water slurry is pumped to a smaller slurry mix tank, where raw water is added to bring the solids content of the slurry to 47.5 weight percent. The slurry is pumped in two stages to about 1300 psig and is then preheated to about 500°F by hot process streams and high-pressure steam.

Gasification (Two Trains)

The hydrogasification reactor consists of four fluidized beds arranged vertically in a common shell. All the beds operate at about 1200 psig and increase in temperature from 600°F at the top to 1850°F at the bottom. Two gasification reactors are required. Each vessel is approximately 25 feet in

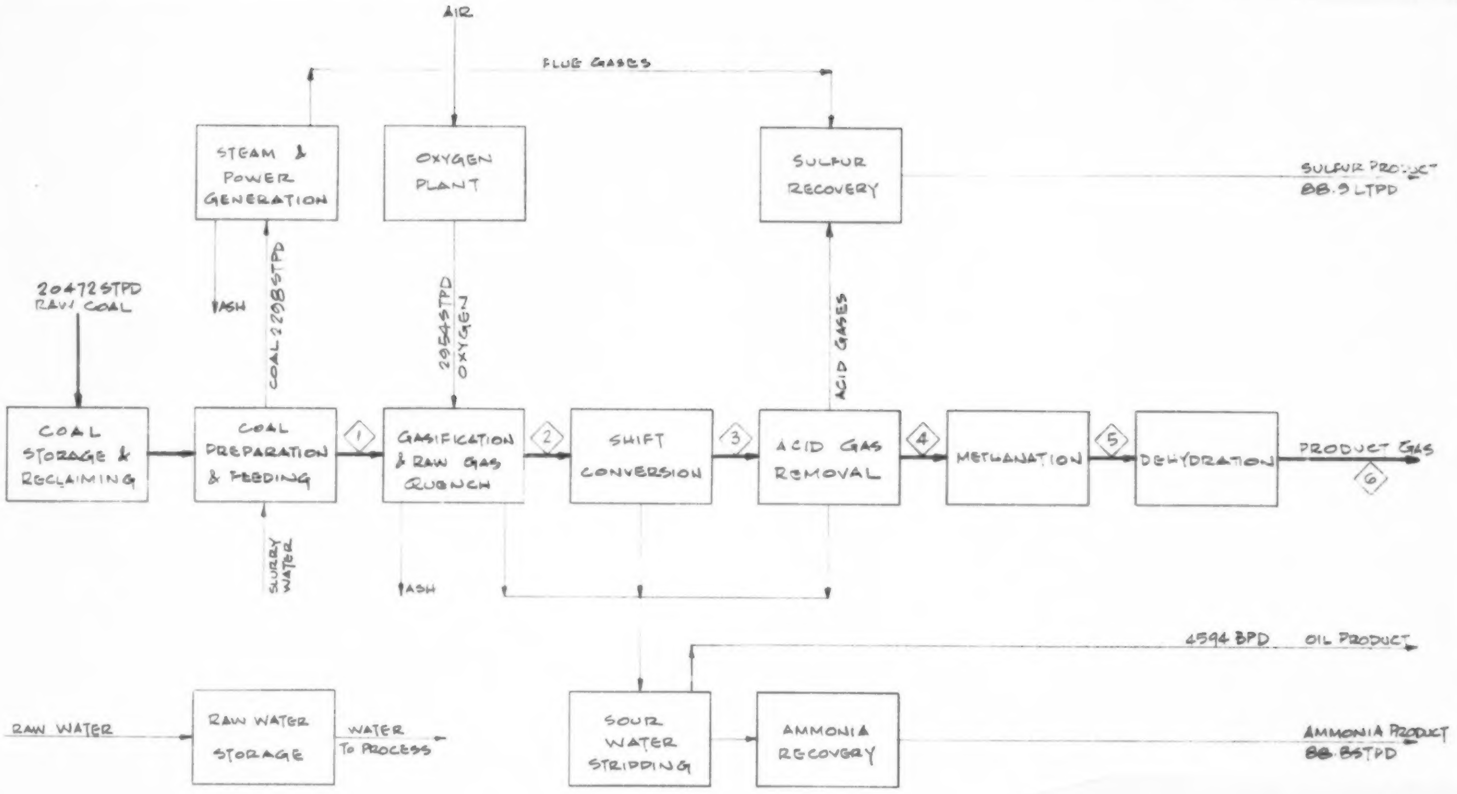
AIR
FLUE GASES
STEAM & POWER GENERATION
OXYGEN PLANT
SULFUR RECOVERY
SULFUR PRODUCT
88.9 LTPD
20472 STPD RAW COAL
ASH
COAL 2298 STPD
2954 STPD OXYGEN
ACID GASES
COAL STORAGE & RECLAIMING
COAL PREPARATION & FEEDING
1
GASIFICATION & RAW GAS QUENCH
2
SHIFT CONVERSION
3
ACID GAS REMOVAL
4
METHANATION
5
DEHYDRATION
PRODUCT GAS
6
SLURRY WATER
ASH
4594 BPD
OIL PRODUCT
RAW WATER
RAW WATER STORAGE
WATER TO PROCESS
SOUR WATER STRIPPING
AMMONIA RECOVERY
AMMONIA PRODUCT
88.8 STPD

Figure 22. HYGAS gasification plant, simplified block flow diagram.

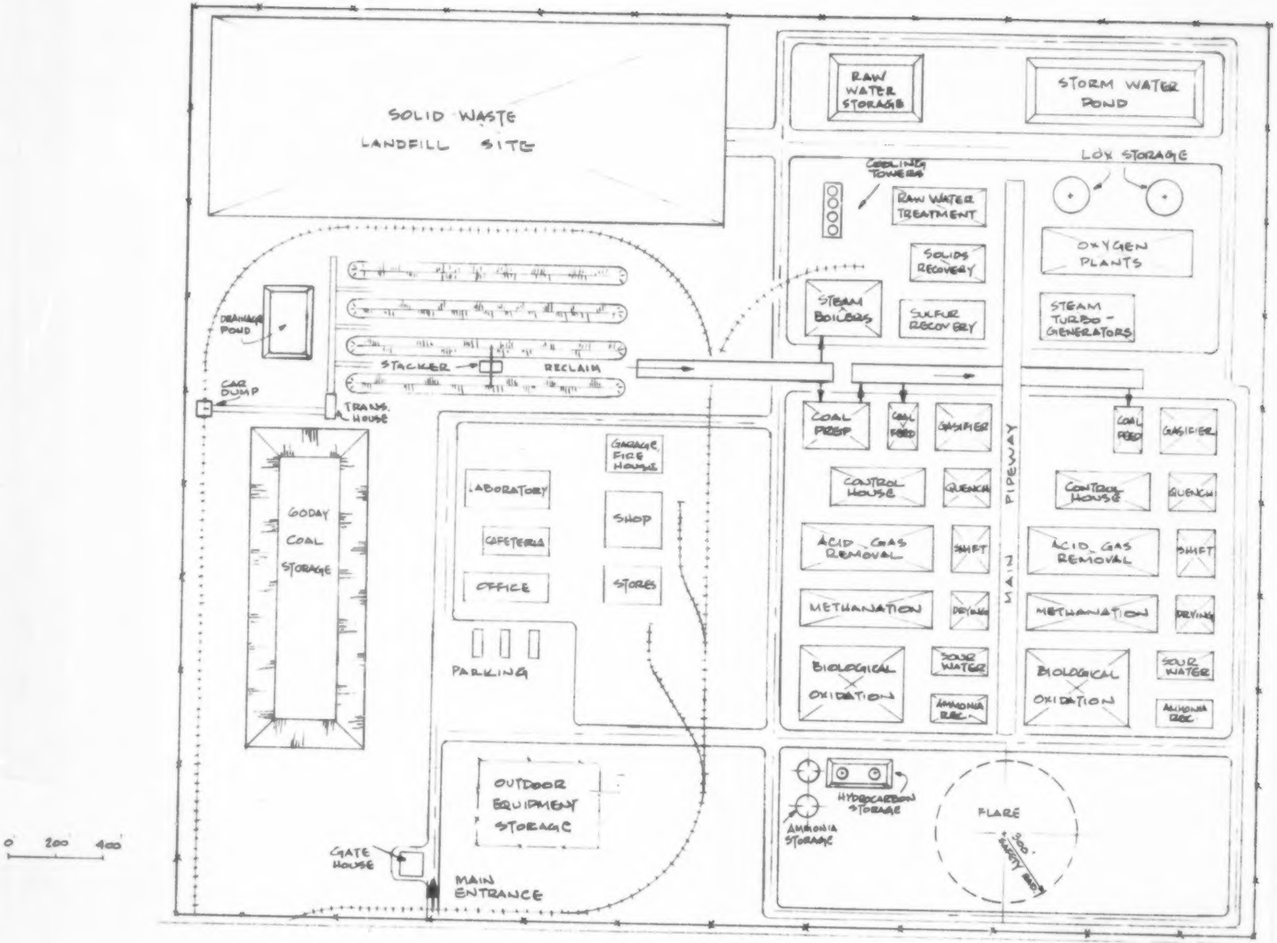
SOLID WASTE LANDFILL SITE
RAW WATER STORAGE
STORM WATER POND
COOLING TOWERS
RAW WATER TREATMENT
LOX STORAGE
OXYGEN PLANTS
SOLIDS RECOVERY
STEAM BOILERS
SULFUR RECOVERY
STEAM TURBO-GENERATORS
DRAINAGE POND
STACKER
RECLAIM
CAR DUMP
TRANS. HOUSE
60DAY COAL STORAGE
COAL PREP
COAL FEED
GASIFIER
CONTROL HOUSE
QUENCH
ACID GAS REMOVAL
SHIFT
METHANATION
DRYING
BIOLOGICAL OXIDATION
SOUR WATER
AMMONIA REC.
MAIN PIPEWAY
GARAGE FIRE HOUSE
LABORATORY
SHOP
CAFETERIA
OFFICE
STORES
PARKING
OUTDOOR EQUIPMENT STORAGE
GATE HOUSE
MAIN ENTRANCE
AMMONIA STORAGE
HYDROCARBON STORAGE
FLARE
300' SAFETY RAD.
0
200
400

Figure 23. HYGAS gasification plant, plot plan.

TABLE 62. ASSUMED COAL FEEDSTOCK PROPERTIES (5)

Composition	Moisture Free	As Received
Proximate		
Volatile Matter, % wt	37.7	29.4
Fixed Carbon, % wt	54.6	42.6
Ash, % wt	7.7	6.0
Moisture, % wt	-	22.0
	100.0	100.0
Ultimate		
Hydrogen, % wt	4.61	3.58
Carbon, % wt	67.70	52.62
Sulfur, % wt	0.66	0.51
Nitrogen, % wt	0.85	0.66
Oxygen, % wt	18.46	14.63
Ash, % wt	7.72	6.00
Moisture, % wt	-	22.00
	100.00	100.00
Heating Value (HHV), Btu/lb	11,290	8,800

TABLE 63. COAL TO PIPELINE GAS DESIGN BASES AND ASSUMPTIONS

Plant Capacity	The design capacity of the commercial plant is 250 billion Btu/stream day (HHV) of synthetic pipeline gas
Coal Receiving	Unit train delivery* and transported into the processing facilities by conveyor belt from dump hopper
Onsite Coal Storage	60 days dead,* 14 days live
Coal Feed Preparation	Spare mills and classifying equipment is provided in an amount equivalent to 25% of total plant capacity
Gasification	A minimum of two gasifiers have been provided; similarly, facilities for gas quench and solids removal will be separate for each gasifier
Gas Treatment	Two trains, 50% each, have been provided for the following major process units: Shift Conversion Acid-Gas Removal Methanation Product Gas Drying Fixed catalyst beds have been designed for 25% of plant capacity, two beds for each 50% train
Oxygen	Two 1500 ton per day oxygen plants have been provided without any spare capacity. Liquid oxygen storage for the output of one plant has been provided
Liquid Effluent	Process liquid effluent treating will have two trains, 50% each; one common spare sour water stripper with its auxiliary equipment has been provided
Solid Waste Disposal	Filtered biological sludge, plant trash and garbage and intermittent basin and equipment cleanout sludges are buried in an onsite sanitary landfill;* all other solid wastes, such as gasifier and boiler ash, and the solids from the wastewater evaporator are prepared for return to the mine by rail car*

(continued)

TABLE 63.(Continued)

Gas Effluent	All gaseous effluents from the plant will meet the prevailing federal and state standards
Plant Water Supply	River water (pumphouse intake system*)
Onsite Water Storage	3 days storage capacity*
Plant Load Factor	90 percent
Plant Operating Life	20 years

* Balance of plant modifications or assumptions different from C.F. Braun & Co. reports (5,6)

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TABLE 64. SUMMARY MATERIAL BALANCE — IGT STEAM-OXYGEN HYGAS PROCESS

Streams	Lb/Hr	Percent of Total
Inlet		
Coal to Process, Dry	1,135,800	22.3
Water in Coal to Process	320,400	6.3
Coal to Steam Plant, Dry	194,800	3.8
Water in Coal to Steam Plant	55,000	1.1
Oxygen to Gasifier	246,200	4.8
Combustion Air, Nitrogen	1,670,300	32.9
Combustion Air, Oxygen	504,600	9.9
Raw Water	962,500	18.9
TOTAL	5,089,600	100.0
Outlet		
Product Gas	446,400	8.8
CO_2 Vent	1,264,700	24.9
Cooling Tower Losses	409,900	8.1
Flue Gas	2,543,800	50.0
Ammonia	7,400	0.1
Sulfur	8,300	0.2
Byproduct Oil	52,600	1.0
Organics Removed in Biox. Unit	6,600	0.1
Waste Solids, Dry	131,800	2.6
Water in Waste Solids	67,900	1.3
Miscellaneous Water Losses	150,200	2.9
TOTAL	5,089,600	100.0

TABLE 65. HYGAS GASIFICATION PLANT — 250 MMM BTU/DAY — OVERALL MATERIAL BALANCE

Stream No.	1		2	3	4	5	6
Description	Process Coal Slurry MPH		Raw Product Gas MPH	Shifted Sour Gas MPH	Methane Feed Gas MPH	Wet Product Gas MPH	Wet Product Gas MPH
C	64,157.0	H_2	24,702.0	35,160.0	35,144.0	3,534.0	3,532.0
H_2	26,212.5	CO	20,762.0	10,280.0	10,252.0	30.0	30.0
N_2	345.2	CO_2	20,772.0	30,372.0	488.0	476.0	476.0
O_2	6,560.2	CH_4	14,214.0	14,206.0	13,996.0	26,018.0	27,008.0
S	234.5	C_2H_6	1,110.0	1,108.0	896.0	—	—
H_2O	69,888.9	NH_3	368.0	—	—	—	—
MPH	167,398.3	H_2S	232.0	220.0	—	—	—
lb/hr	2,307,408	COS	9.6	4.4	—	—	—
lb/hr ash	87,792	C_6H_6	168.0	136.0	—	—	—
Total lb/hr	2,395,200	C_7	326.0	—	—	—	—
		H_2O	53,726.0	76.0	4.0	28.0	4.0
		MPH	136,389.6	91,562.4	60,780.0	30,086.0	30,050
		lb/hr	2,854,200	1,986,600	630,920	445,996	445,400

diameter and approximately 280 feet in height. The following is a description of the processing steps that take place within the hydrogasification vessel.

Slurry Dryer--

Coal is dried in the first stage by vaporizing the slurry water. The slurry from the slurry preparation section is injected into the top fluidized bed. The hot gases passing upward from the hydrogasification stages maintain the bed in a fluidized state and flash the slurry water from the coal particles. The dry coal flows from this bed by gravity into the first hydrogasification reaction stage. The operating conditions of the slurry dryer bed are 600°F and 1205 psig and a residence time of 15 minutes.

Low-Temperature Reactor--

Hydrogasification begins in the second zone — the low-temperature reaction stage. The dry coal is flash-heated to the reaction temperature. The residence time in the low-temperature reaction stage is measured in seconds, and the flow characteristics are cocurrent, dilute-phase contact of the solids with the hot hydrogen-rich gas rising from the higher-temperature stage below. In this first stage of reaction, the short residence time and high pressure favor devolatilization and the rapid-rate, direct methanation of the more active constituents of the coal. The hot offgases from this stage rise to the slurry drying bed above, and the partially gasified coal is diverted to the high-temperature stage below. The operating conditions of the low-temperature bed are 1360°F and 1210 psig and a residence time of ten seconds.

High-Temperature Reactor--

Hydrogasification of the less reactive carbon continues in the dense-phase, fluidized, high-temperature reaction stage. The less reactive carbon requires a temperature of about 1720°F and a longer residence time to achieve adequate reaction. The high pressure aids the direct methane production. Gases from this stage proceed upward to the low-temperature reactor, and the residual char is diverted to the steam-oxygen gasifier below. The operating conditions of the high temperature bed are 1720°F and 1214 psig and a residence time of 44 minutes.

Steam-Oxygen Gasifier--

The hydrogen-rich gas for the reaction stages is manufactured in the fourth (bottom) zone by the reaction of steam and oxygen on the carbon in the residual char from the high-temperature reactor. Ash is expelled from the base of the hydrogasifier and transported in a water slurry to the ash handling facility. The operating conditions of the steam-oxygen bed are 1850°F and 1219 psig and a residence time of ten minutes.

Raw Gas Quench (Two Trains)

Raw gas from the gasifier at 600°F is quenched and scrubbed with water in a column to remove entrained solids. The gas is then further cooled by indirect heat exchange to about 460°F. At this temperature, the gas contains the proper amount of water vapor for shift conversion. The scrubbed solids are sent as a slurry to the solids recovery facility.

Shift Conversion (Two Trains)

The H_2/CO ratio of the raw gas must be adjusted prior to methanation. This is done in the Shift Conversion Unit. The shift converters are fixed-bed catalytic reactors containing a cobalt molybdate catalyst. Part of the raw gas is bypassed around the shift converters to achieve the desired H_2 to CO ratio. Heat evolved is removed by heat exchange. Steam contained in the shift effluent gas is condensed, the condensate going to a condensate stripper. The cooled gas enters the acid gas removal unit.

Acid Gas Removal (Two Trains)

This unit removes H_2S and any COS and CS_2 from the gas to protect the methanation catalyst. Also, CO_2 must be removed to allow the product gas to meet quality specifications after methanation. Acid gas is removed by the Selexol Process, a proprietary process of Allied Chemical Corporation. Waste sulfur-bearing gases from this unit are routed to the sulfur recovery facilities. As designed, waste CO_2 goes either to the plant inert gas system or to the atmosphere through a vent stack. The CO_2 and nitrogen rich gas also contains some trace of sulfur and hydrocarbon compounds. These two gas streams will probably need to be incinerated or at least wet-scrubbed before release to the atmosphere.

The acid gas removal unit consists of two separate stages. The first stage removes essentially all of the H_2S and other sulfur compounds and some of the CO_2. The second stage removes nearly all of the remaining CO_2. This design maximizes the sulfur compound concentration in the feed to the sulfur recovery unit.

Methanation and Dehydration (Two Trains)

The methanation unit converts the purified raw gas into the final product gas interchangeable with natural gas. Methanation is carried out in a series of three spherical fixed-bed catalytic reactors. The methanation reaction is highly exothermic, and the reaction temperature is controlled by a combination of heat recovery and hot product gas recycle. The hot recycle allows the recovery of essentially all of the methanation heat of reaction as high-level useful energy. The methanation reaction also produces water, the bulk of which is condensed.

After methanation, the final product gas is cooled, then dehydrated, using a triethylene glycol drier. Glycol is thermally dehydrated (regenerated), and the water-rich gas is vented to the atmosphere.

The product gas (274 MMSCFD) then leaves the plant at about 1000 psig and is sent through a short connector pipeline to an interstate gas pipeline.

Auxiliary Systems

Sulfur Recovery--

Sulfur in the feed coal (93 long tons per day) is converted by either gasification or combustion to H_2S, COS, or SO_2. The quantities of such gases

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which may leave the plant are set by environmental regulations (see environmental assumptions). The sulfur recovery is accomplished by the use of the IFP Stackpol process, a proprietary process by Institute Francais du Petrole. This unit treats the flue gases from combustion and acid gases from the acid gas removal unit and the condensate stripping facilities. Sulfur compounds are removed from these gases and converted to elemental sulfur (molten), which is sold as a byproduct (88.9 LTSD) and shipped from the plant by truck. As designed, the treated gases leave the plant through a tall stack. These gases might need some additional cleanup such as scrubbing to remove trace quantities of COS and H_2S if environmental regulations are made more stringent. Flyash removed from the flue gases is sent to solids recovery.

Sour Water Stripping (Two Trains)--
Sour water is produced in the gas quench, shift conversion, and acid gas removal sections. In the IGT Steam-Oxygen HYGAS process, the quench condensate (about 1500 gpm) does not contain phenols, while the shift condensate (about 1550 gpm) does. These are handled in two separate sour water stripping units. Stripped quench condensate is reused directly in the plant water systems. Stripped shift condensate goes to a biological oxidation system for consumption of the phenols before reuse as coal slurry makeup water. Acid gases from the sour water strippers are passed through ammonia recovery and sent to sulfur recovery.

Ammonia Recovery--
Ammonia in the overhead streams from the sour water strippers is recovered by use of the PHOSAM-W Process. This process is offered by U.S. Steel Engineers and Consultants, Inc. Ammonia is recovered in the anhydrous form by this process. Approximately 88.8 STPD are recovered and stored in tanks for truck shipment offsite as a saleable byproduct.

Oil Recovery--
The HYGAS process also produces a hydrocarbon oil product which is basically a mixture of benzene and toluene. This oil product is recovered in the sour water stripping system and pumped to storage for eventual sale as a byproduct.

Oxygen Plant--
Two 1500-ton-per-day oxygen plants supply the oxygen requirements for gasification. Ambient air is filtered and compressed to the required operating pressure. The air compressor configuration generally consists of an axial-type first-stage machine with water aftercooling and liquid knockout capability. This is followed by a centrifugal-type second-stage compressor, also equipped with water aftercooling and liquid knockout capability. The compressed air then enters a reversing circuit of air-oxygen-nitrogen exchangers, where it is cooled to temperatures which permit carbon dioxide and water to be separated from air by solidifying out on the exchanger surface. The air then passes through the liquefier exchanger for further cooling. From the liquefier exchanger, the air is subjected to high-pressure and low-pressure distillation, where the components of air — oxygen and nitrogen — are separated by fractionation.

The oxygen product is taken from the low-pressure column and exits the system by passing back through the liquefier and reversing exchangers while being heated. The oxygen product is then compressed to the required gasification pressure.

Steam and Power--
The IGT Steam-Oxygen HYGAS process does not recover enough high-pressure steam from the process to satisfy all motive and process steam requirements. Therefore, three 50-percent-capacity coal-fired boilers are installed. The boilers produce approximately 1.5 million pounds per hour of 1500 psig steam. In-plant power is generated by three 50-percent-capacity steam turbine-driven generator sets. The net power output of the generator sets is approximately 38 MWe.

Water Systems--
The plant is designed for zero aqueous discharge of process wastewater. Only storm runoff will be discharged to the river. About 1925 gpm of river water is consumed by the plant (Figure 24). Evaporation and residual water present in solid wastes account for this consumption. Water enters with coal and is also produced in the methanation step (and in sulfur recovery, combustion, etc.). Cleanup and reuse of process effluents minimize the makeup demand. A multiple-effect evaporator recovers additional water from the high TDS process blowdown streams.

Intake water is withdrawn from the river and pumped to an onsite river water storage pond. Three half-capacity pumps in the intake pumphouse supply water through a 12-inch diameter pipeline. The 8.6-million-gallon basin provides storage for three days of makeup water. Two pondwater pumps feed the plant water systems.

About 470 gpm of pondwater is pumped to coal feed preparation and to the gasifiers as slurry makeup and ash quench makeup, respectively. The balance of the plant feedwater is cold lime-softened, clarified, and filtered. About 400 gpm of softened water is used as utility water and potable water in the plant. About half of this is recovered and resoftened. Nearly all of the other softened water is fed to the high (H.P.) and low (L.P.) pressure boiler feedwater treating systems. High-pressure BFW makeup treatment consists of reverse osmosis followed by mixed bed demineralization for residual TDS removal (different from Braun report). Reverse osmosis concentrate (brine) and ion exchange regenerant wastes are sent to the wastewater evaporator for further concentration and water recovery. A separate condensate polishing system removes residual TDS from methanation product water which is then used as BFW makeup (about 730 gpm). Total makeup to the deaerator is about 1738 gpm, excluding the steam system condensate return.

Low-pressure BFW makeup is sodium-zeolite-softened and deaerated. Only about 20 gpm of lime-softened river water is used as L.P. makeup. The remainder is stripped condensate from raw gas quenching and a small stream from acid gas removal. Sodium zeolite regenerant waste and lime softener sludge blowdown are processed in the wastewater evaporator.

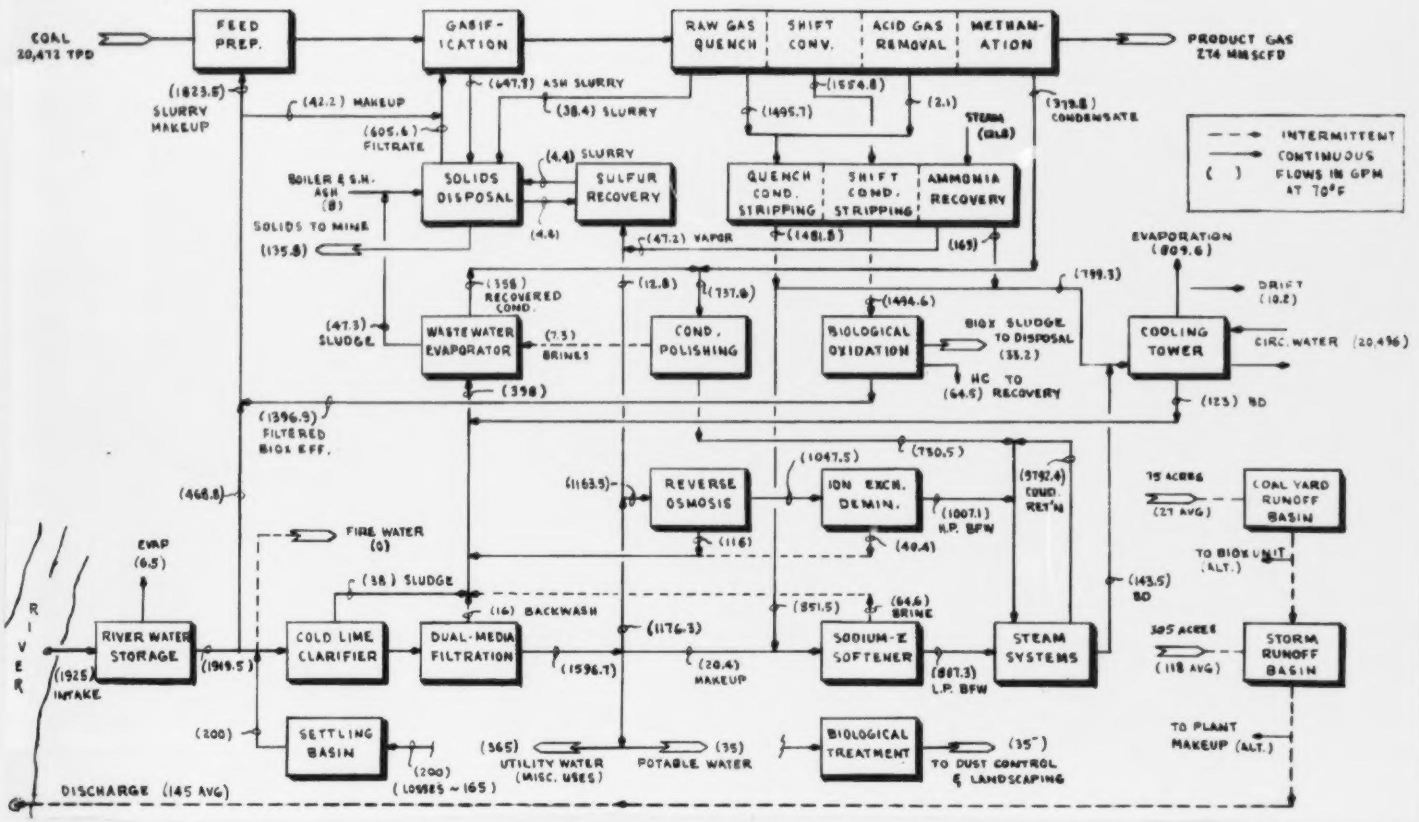
COAL 20,472 TPD
FEED PREP.
(1823.5) SLURRY MAKEUP
(42.2) MAKEUP
GASIF-ICATION
(647.3) ASH SLURRY
(38.4) SLURRY
(605.6) FILTRATE
RAW GAS QUENCH
SHIFT CONV.
ACID GAS REMOVAL
METHAN-ATION
PRODUCT GAS 274 MMSCFD
(1554.8)
(1495.7)
(2.1)
STEAM
(319.8) CONDENSATE
INTERMITTENT
CONTINUOUS
( ) FLOWS IN GPM AT 70°F
BOILER & S.H. ASH (8)
SOLIDS DISPOSAL
(4.4) SLURRY
SULFUR RECOVERY
(4.4)
SOLIDS TO MINE
(135.8)
QUENCH COND. STRIPPING
SHIFT COND. STRIPPING
AMMONIA RECOVERY
(47.2) VAPOR
(1481.5)
(169)
EVAPORATION (809.6)
DRIFT (10.2)
(799.3)
(356) RECOVERED COND.
(12.8)
(737.6)
(1494.6)
(47.3) SLUDGE
WASTE WATER EVAPORATOR
(7.5) BRINES
COND. POLISHING
BIOLOGICAL OXIDATION
BIOX SLUDGE TO DISPOSAL (33.2)
HC TO (64.5) RECOVERY
COOLING TOWER
CIRC. WATER (20,436)
(398)
(125) BD
(1396.9) FILTERED BIOX EFF.
(1047.5)
(730.5)
(468.8)
(1163.5)
REVERSE OSMOSIS
ION EXCH. DEMIN.
(1007.1) H.P. BFW
(5792.4) COND. RET'N
75 ACRES
(27 AVG)
COAL YARD RUNOFF BASIN
TO BIOX UNIT (ALT.)
EVAP (6.5)
FIRE WATER (0)
(116)
(40.4)
(143.5) BD
(38) SLUDGE
(16) BACKWASH
(1176.3)
(851.5)
(64.6) BRINE
305 ACRES
(118 AVG)
STORM RUNOFF BASIN
R I V E R
(1925) INTAKE
RIVER WATER STORAGE
(1949.5)
COLD LIME CLARIFIER
DUAL-MEDIA FILTRATION
(1596.1)
(20.4) MAKEUP
SODIUM-Z SOFTENER
(867.3) L.P. BFW
STEAM SYSTEMS
(200)
SETTLING BASIN
(200) (LOSSES ~ 165)
(365) UTILITY WATER (MISC. USES)
(35) POTABLE WATER
BIOLOGICAL TREATMENT
(35*) TO DUST CONTROL & LANDSCAPING
TO PLANT MAKEUP (ALT.)
DISCHARGE (145 AVG)

Figure 24. HYGAS simplified water balance.

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L.P. BFW is used in various process steam generators to generate 50 psig and 150 psig steam for process use. H.P. BFW is fed to the three 50-percent-capacity coal-fired auxiliary boilers and to the methanator waste heat boilers and coal-fired superheaters to generate 1450 psig process steam. Six hundred psig steam for process use is driver exhaust steam from the acid gas removal compressor. The bulk of the steam system condensates is of excellent quality and hence returned to the H.P. feedwater system.

All other water demands are met from recycle of process effluents. Makeup to the cooling water system is a combination of blowdown from the steam generators (143 gpm), part of the stripped condensate from the raw gas quenching (630 gpm), and effluent from the ammonia recovery unit (169 gpm). The cooling water system removes process heat and rejects it to the atmosphere in an induced-draft cooling tower (four cells). The circulating-water rate is only about 20,500 gpm. The cooling range is 35°F. Air coolers are used wherever possible to minimize the heat load on the evaporative (wet) cooling system. Evaporation and drift losses from the tower average 820 gpm. Blowdown (123 gpm) is routed to the wastewater evaporator. The tower operates at six to seven cycles of concentration. A chromate-zinc based corrosion inhibitor is added to the circulating water. Chlorine gas is used in shock treating the CW for biofouling control.

Shift conversion condensate is a major process effluent stream contaminated with the organics even after stripping for NH_3 removal. A three-stage biological oxidation system (two trains) is provided to treat this almost 1500 gpm stream. Stripped water first passes thorugh a dissolved air filtration (DAF) unit to recover flotable hydrocarbons. DAF effluent is treated for dissolved organics removal in three activated sludge-clarifier units operated in series. Waste sludge generated in each unit is thickened in a second DAF unit. The thickened sludge is aerobically digested and then vacuum filtered, producing a sludge cake for land disposal. The cake (7.5 tpd) is transported by belt conveyor to the plant solid waste loadout facilities from which it is trucked to an onsite landfill. The bio-treated effluent from the third-stage clarifier is filtered in a gravity sand filter. Filtered effluent is pumped to coal feed preparation for reuse as a portion of the coal slurry makeup water.

The plant's high solids blowdown streams total about 205 gpm and contain about 19 tpd of total solids. A multiple-stage flash evaporator concentrates these streams into a slurry waste by evaporating and recovering most of the water. Evaporator condensate is recycled to the H.P. BFW makeup system after polish demineralization. The evaporator brine slurry is pumped to the solids recovery system.

Sanitary wastewater (35 gpm) is collected in a separate sewer system and biologically treated in a package unit which includes tertiary filtration and disinfection with sodium hypochlorite. Treated sanitary effluent is used for landscaping water and dust control within the plant. Waste sludge is aerobically digested and filtered.

Storm runoff from the process areas and the coal storage area is collected in separate storm drainage systems.

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Solid Waste Disposal--
The major solid wastes generated in the plant are: (1) ash from the gasifiers (54 tph), (2) scrubbed ash solids from raw gas quenching (2.1 tph), (3) boiler fly ash from sulfur recovery (1.5 tph), (4) boiler and superheater ash from coal-fired steam generators (7.5 tph), (5) solids from the wastewater evaporator (1600 lb/hr), (6) waste biological sludge (9.75 tph at 15 percent solids), and (7) general plant trash and garbage (1700 lb/day). All except the last two are prepared in the solids recovery facility for return to the mine by rail car. The slurry streams are thickened, blended in pug mills, and transported by belt conveyors to sludge loadout bins. Ash slurry from the gasifiers is diluted to a ten-percent slurry and passed over sieve bends to concentrate the coarser fraction. The fines portion (-100 mesh) is combined with quench ash solids and fly ash and settled in a gravity thickener. The thickened slurry underflow is vacuum filtered to an 80-percent solids cake which is fed to the pug mill. Clarified slurry water is recycled to the gasifiers for ash quenching.

Wastewater evaporator slurry is combined with the boiler and superheater ash and fed to the pug mill. The blended solids from the pug mill total about 66 tph of dry solids and about 34.0 tph of water. At about 70 lb/cu ft, some 68,500 cubic feet per day of solid waste is fed to the loadout bins (about 788,400 tpy). Three days of solids storage capacity is provided by two 4000-ton silos. Solids are flood-loaded into a unit train on occasion for the return trip to the mine.

Filtered biological sludge, plant trash and garbage, and intermittent basin and equipment sludges are buried in an onsite sanitary landfill.

Plant Thermal Balance

Table 66 shows an overall plant thermal efficiency of 77.6 percent, of which the product SPG represents 69.7 percent. The conversion plant produces a more useful (clean gas) and more valuable product than the feed coal. The conversion penalties are the conversion costs and the energy losses. Energy loss is primarily in the form of heat rejected to the atmosphere.

COAL GASIFICATION PLANT COSTS

Capital and operating costs for the conceptual HYGAS facility were updated to first quarter 1978 from the estimate presented by C. F. Braun & Co. in a 1976 ERDA report (5). The capital costs were broken down by major process unit, and the same general format has been retained (see Table 67). The escalation methods are described in Appendix C. Nonprocess changes in the conceptual design included addition of a rail car hopper dump, a river water intake system (with a reduction of the water storage pond size), a solid waste loadout facility, an onsite landfill, an access road, a rail spur, and a three-mile gas pipeline. Only major cost items were added. Minor cost items were assumed to be offset by the smaller air-moving equipment (fans, blowers, etc.) that this conceptual plant would have due to altitude of 1400 feet instead of 3330 feet.

TABLE 66. SUMMARY ENERGY BALANCE — IGT STEAM-OXYGEN HYGAS PROCESS

Element	MM Btu/hr	Percent of Total
Energy Input		
Coal to Process, HHV	12,749	85.4
Coal to Steam Plant, HHV	2,186	14.6
Total Input	14,935	100.0
Energy Distribution		
Product Gas, HHV	10,415	69.7
Byproducts, HHV		
Ammonia	67	0.5
Sulfur	33	0.2
Oil	1,071	7.2
Subtotal Product and Byproducts	11,586	77.6
Consumption and Losses	3,349	22.4
Total Energy Distribution	14,935	100.0
Cold Gas Efficiency, Percent		69.7
Plant Thermal Efficiency, Percent		77.6

TABLE 67. HYGAS CAPITAL COSTS

Element	$1,000,000's
Coal Storage and Reclaiming	13.2
Coal Preparation	16.6
Coal Feeding	25.5
Gasification	44.0
Raw Gas Quenching	18.6
Shift Conversion	30.4
Acid Gas Removal	105.7
Methanation	28.4
Liquid Effluent Treatment	56.8
Sulfur Recovery	58.7
Solids Disposal	10.8
Product Gas Drying	0.8
Steam and Power	133.0
Plant Water System	16.6
Oxygen Plant	44.0
General Facilities	68.6
DIRECT FIELD COST	671.7
Indirect Field Cost	100.8
TOTAL FIELD COST	772.5
Engineering Services	92.7
	865.2
Allowance for Uncertainty	129.8
TOTAL CONSTRUCTION COST	995.0
Land	1.0
Other Owner Costs	8.8
Startup	29.9
Allowance for Funds During Construction	155.2
FIXED CAPITAL INVESTMENT	1,189.9
Working Capital	23.3
TOTAL CAPITAL COST First Quarter 1978, Price and Wage Levels	1,213.2

The total capital cost of $1.213 billion represents an investment of about $4350 per MM Btu/day of gas output. This cost is about 14 percent higher than C. F. Braun's January 1, 1976 capital cost (5). Pollution control equipment costs were not identified separately by Braun. A rough value can be obtained from the sum of the process unit costs for liquid effluent treatment, sulfur recovery, and solids disposal — about $126 million or 18.8 percent of the direct field cost (some portion could reasonably be attributed to byproduct recovery). Some additional pollution control equipment items are included in the costs for the coal-handling systems.

The annual operating costs in Table 68 indicate that labor constitutes nearly 30 percent of the annual operating expenses. Taxes and insurance are about one-third of the operating costs. Byproduct credits of $28.9 million per year for sulfur, ammonia, and oil reduce the annual operating cost (excluding feedstock) to $53.6 million or about $0.65/MM Btu of gas product instead of $1/MM Btu.

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TABLE 68. ANNUAL OPERATING AND MAINTENANCE COSTS* — HYGAS

Element	$1,000,000's
Water	0.4
Catalyst and Chemicals	3.7
Operating and Maintenance Labor	24.5
Operating and Maintenance Supplies	12.5
Administration and General Overhead	14.7
Local Taxes and Insurance	26.7
TOTAL ANNUAL OPERATING COST	82.5
Byproduct Credits	(28.9)
NET ANNUAL OPERATING COST First Quarter 1978, Price and Wage Levels	53.6

*Excluding coal feedstock.

The cost for returning solid waste (mainly ash) to the mine and burying it under overburden is assumed to be included in the cost of the coal. Were the wastes classified as hazardous materials, the cost for environmentally safe disposal could be quite high. A separate, secure landfill site might have to be developed and operated by the plant if the mine site were not suitable for disposal. Assuming a disposal cost of, say, $10/ton, the annual cost would be nearly $8 million or about $0.10/MM Btu of gas output.

Figure 25 shows the sensitivity of gas cost to the cost of coal for utility and private financing. The gas production costs (zero coal cost) are $2.42 and $3.75/MM Btu, respectively. Both are considerably above the current regulated price of new interstate gas. The gas cost approximately doubles for utility and private financing at coal costs of $30/ton and $45/ton, respectively. At $15/ton ($0.85/MM Btu), the gas price required by a private developer is about $5/MM Btu.

COAL GASIFICATION ENVIRONMENTAL IMPACTS

Coal Procurement Impacts

About 6.7 million tons per year of western coal will be required from surface mines as feedstock for the HYGAS plant. Impacts on land, water, air, and biology will be as described in Section 3 (Coal Procurement Impacts), although the quantity of coal mined (almost seven times the coal-to-power needs) and the characteristics of the mine site itself may modify the significance of these impacts on a local and regional scale.

Topography--

The normally gently rolling terrain will be disrupted at the mine site, with overburden being removed (excavated) and stockpiled prior to coal removal. Land reclamation will result in an approximation of the original topography, but it is likely that elevations of hills will be lower by at least the amount of coal and other materials removed; that normal topographical irregularities will be replaced with a more regular, rolling terrain; and that the contours of the mined area will not be exactly as the original contours. However, given past uses of the area, the probable continued use for strip mining, and the possible use of the mine as a disposal site for HYGAS solid waste, these topographical changes will not be significant to the regional topography.

Soils and Geology--

Removal of the required 6.7 million tons of coal per year will result in three direct changes in regional soils and geology:

- Disruption of the natural geologic structure and the physical properties of the overburden by destroying the original stratification of beds, geologic structures, and natural strength
- Removal and consumption of the coal, a nonrenewable resource
- Intermixing of soil horizons, possible bringing to the surface materials that may be harmful to plant growth

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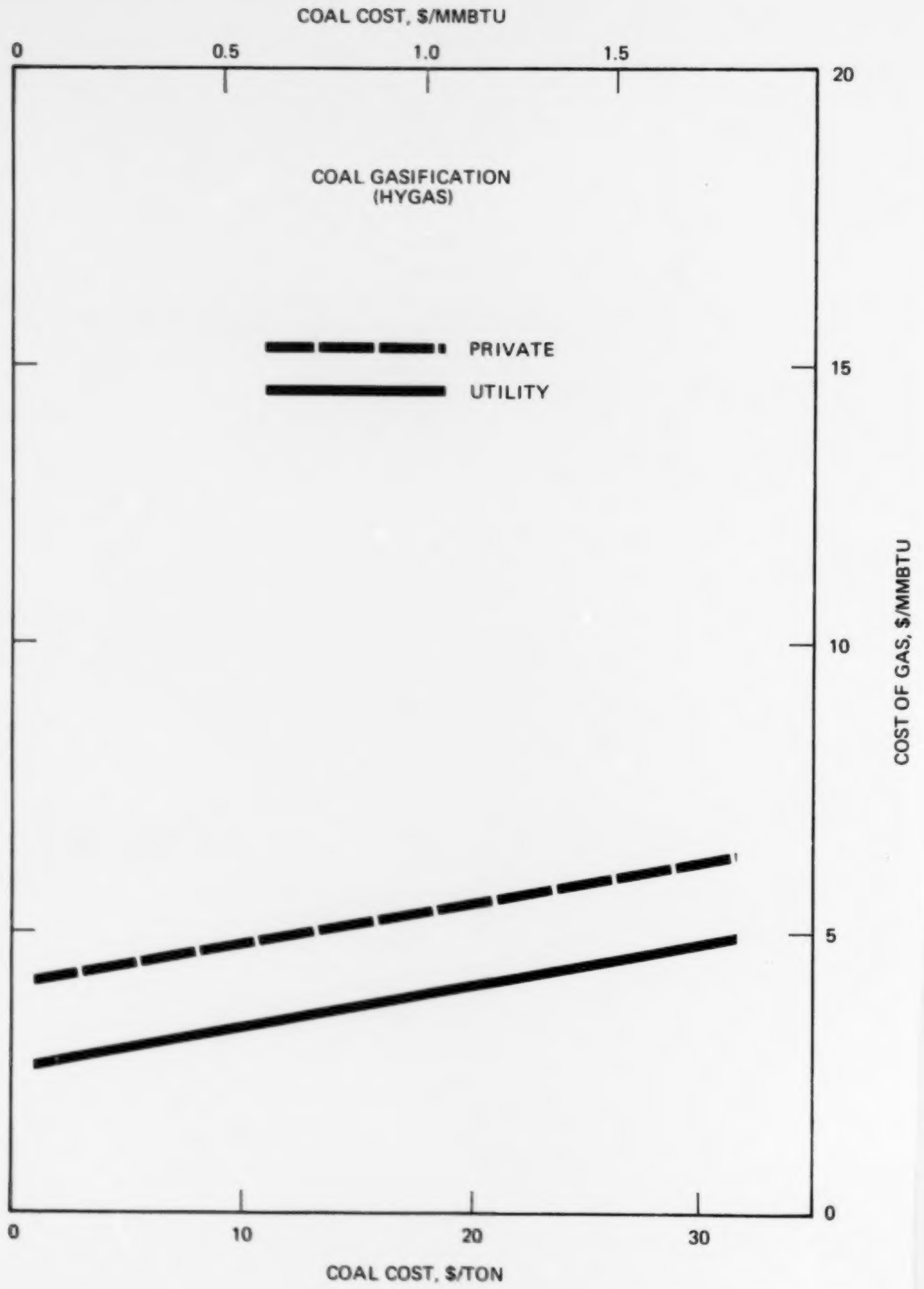

Figure 25. Effect of coal cost on cost of gas with both private and utility financing.

Stockpiling of soils and subsoil may also result indirectly in "bulking," or an increase in volume, of the overburden, which means that, upon reclamation, the fill would be less dense and subject to compaction and settling over time. In addition, stockpiling of topsoil may result in lowered productivity of the soil since the stockpile will become biologically sterile with time. Upon reclamation, productivity cannot be restored until the area has been geologically reinoculated and the normal bacteriological and mycological populations have been restored.

Since wind and erosion are serious problems in the region and wind speeds may average more than 10 mph, loosened silt, sand, and clay-size particles of soil and subsoil will be moved and add to the loss of productive soil material. In addition, surface runoff and consequent soil erosion and sedimentation will result where soil permeability and infiltration are reduced by compaction from mining activities. Also, alterations of stream beds and watersheds will affect offsite erosion.

Groundwater--
Possible impacts on groundwater (depending on aquifer structure at the mine site and the location of recharge area) are:

- Removal of existing shallow aquifers, or portions thereof, and replacement by unstructured overburden or spoil
- Reversal of recharge/discharge relationships by interfering with recharge areas and/or draining aquifers (dewatering) during the mining operation
- Altering groundwater quality by changing the sources of chemicals in the water (rock and biosphere), changing hydraulic, thermal, and chemical gradients; and by losses of precipitation, ion exchange, sorption, and biosphere effects on the groundwater

The effect, whether permanent or temporary, cannot be predicted without studies of mine-site groundwater. However, while changes in groundwater availability and quality are likely and will be adverse, their regional significance will depend on present groundwater problems as a result of mining, regional dependence on groundwater as a potable water supply, and future needs which might require protection of all potential water supplies.

Surface Water--
Changes in topography will result in changes in drainage, possibly altering the quantity and quality of water downstream of the mine. Strip mining and overburden stockpiles near rivers or streams can result in erosion, increased turbidity, and siltation. In addition, physical barriers to runoff, including removal of streams and small watersheds, can affect river flows locally. Uses of erosion control methods and reclamation of the mine site as mining progresses (rather than long-term stockpiling) will reduce the long-term significance of these effects.

Air Quality--
Removal of vegetation and disruption of topsoil will contribute to increased particulate emissions in the form of fugitive dust. The quantity in tons per year will be proportional to the acreage mined per year (about 100 acres of surface) and can contribute significantly to the particulate concentration in the air.

Vegetation--
Approximately 100 acres per year of prairie species will be removed in the course of mining. While this disturbance is not significant to the regional ecology (which is predominantly grazing or agricultural land), two factors could increase the significance of the impacts:

- This amall acreage, in addition to that disturbed by 12 to 15 other mines in the county, could significantly reduce the amount of native vegetation in the region at any one time
- The revegetation of prairie vegetation may be limited by available water, reduced soil productivity, and the cost of fertilizers, resulting in the use of forage species more tolerant to the new conditions

The net result could be a significant replacement of native species by forage species which, in the long term, may not support the same animal species or diversity and which may be less productive than native plants.

Wildlife--
Revegetated grasslands, particularly those specifically planted for grazing use, do not support as diverse a wildlife population as native grasslands. Populations of deer and antelope may not return after revegetation because of changed plant species and topography. Species dependent on specialized vegetation associations (sand hills, riparian or flood plain, cross timbers) may be permanently lost if these vegetation types are removed. Waterfowl may no longer visit marshy areas on or near the mine site because of changes in topography and drainage patterns which may eliminate or reduce wetland areas. All organisms associated with streams or livestock ponds will be destroyed when mining activities excavate these areas.

In addition, the normal wildlife populations in the removed vegetation types will be displaced or removed when the vegetation is removed. In both instances, increases in mortality of local species will result.

Nearby populations will be available to repopulate revegetated habitat should the area be able to support these animals. Some species, such as raptors, may benefit, since more open grassy fields will likely support larger populations of prey species while grazing is prohibited. However, decades may be required for restoration of habitat for species dependent on mature woodlands.

Land Use--
Careful planning of mine-site reclamation keyed to simulate or even enhance alternative land use (i.e., recreational plans, wildlife management, soil

enhancement for agriculture, woodlot planting) may benefit future uses of the area. Present uses of the land surface will be preempted during mining and some uses may be restricted after revegetation:

- Overburden compaction and settling may restrict building on the reclaimed site
- Reduced soil productivity may reduce the value of the area to agriculture or grazing
- Present recreational uses (hunting) will be eliminated during mining and may not be appropriate in the reclaimed areas

Aesthetics--
Contrasts in color (variations in soil color, exposed coal beds, and subsoils), land forms (open pits, service roads cut into hillsides, unshaped stockpiles of overburden and topsoil), and texture (bare soil-vegetation) will make the mine site aesthetically displeasing.

Social and Economic Effects--
The major socioeconomic impacts generated by strip mining include:

- Increases in population and employment associated with expanded mining efforts
- Increases in regional and personal incomes as a result of expansion of mine-related employment and the sale of coal
- Increased demand for goods and services proportional to population increases, but offset at least partially by increased income

Most of the new employees probably will be hired from the local labor pool (skilled and unskilled), but some population increase may also result. Net socioeconomic impacts are likely to be beneficial.

Table 69 presents a summary of likely coal procurement impacts.

Plant Impacts

The coal gasification plant will be constructed over a five-year period, start of engineering to construction completion, and will be operated for 20 years before decommissioning. The peak construction work force will be about 3000. More than 700 full-time employees will constitute the operating staff. Impacts to the environment will result from plant construction and from plant operation. In this brief environmental assessment, emphasis is placed upon estimation of plant operation impacts for a hypothetical site in the midwest. Important construction impacts are noted in less detail.

The plant will produce 82.125 trillion Btu/yr of thermal power in the form of clean fuel gas for offsite consumption. However, the plant will also

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TABLE 69. PROCUREMENT IMPACT SUMMARY

Environmental Factors	Coal Mining Impacts	Mitigating Measures
Topography	Minor changes in land form after reclamation	Mine-site reclamation to simulate existing topography
Soils and Geology	Possible settling and compaction of reclaimed area; reduced soil productivity; consumption of nonrenewable resource (coal)	
Groundwater Quality	Possible interruption or loss of aquifers (shallow) and recharge areas as well as related change in groundwater quality	
Surface Water	Alteration of drainage patterns, flows; increased erosion and siltation in streams; losses of some tributaries	Mine-site controls on drainage; reclamation to restore drainage if possible
Air Quality	Increased particulate emissions-fugitive dust	
Vegetation and Wildlife	Loss of native grasses and associated animal species; possible long-term reduction in plant and animal diversity, production	Revegetation plans, wildlife management incorporated into reclamation of mine site
Land Use	Short-term commitment to mining; potential long-term reduction in productivity altered uses resulting	Reclamation of mine site
Aesthetics	Sharp visual contrast but not significant given surrounding land uses; short-term	Reclamation

(Continued)

TABLE 69. (Continued)

Environmental Factors	Coal Mining Impacts	Mitigating Measures
Community Economy	Potential for increased employment, personal and regional income	
Community Population and Services	Small population increase possible with equivalent increase in demand for goods and services	
Labor Availability	Local labor pool adequate	Training programs to be initiated
Transportation	Mine-site roads required - no discernable effect; local congestion may occur on haul roads between mine site and plant at times	

consume resources that will not then be available for alternative uses. Tables 70 and 71 summarize an estimate of principal resources consumed by the plant. Resources consumed during plant construction will include fuel, power, water, chemicals, plant construction materials, and manpower.

Physical/Chemical Emissions and Impacts--
The operating facility will be a source of air, water, and solid waste emissions which will affect the environment around the plant. Emissions and their general impacts have been estimated and are discussed in the following subsections. The C. F. Braun report (5) is the primary source of process information used in the assessment, with some assumptions made where little or no information was available.

Air Emissions--The gasification plant will contain relatively few point emission sources. Table 72 presents estimates of pollutant discharges to the atmosphere. Fugitive dust from coal handling represents one emission category that is difficult to predict with confidence. It is anticipated that dust control techniques such as telescopic chutes, enclosures of transfer points, wet chemical suppression, and sealing of dead storage piles will be used to control windblown dust losses in exposed transfer operations. The high wind speed at the site would result in considerable windblown losses if such control techniques were not practiced. There are still likely to be substantial releases of coal dust from coal handling and storage. Values in Table 72 are very rough estimates. A substantial fraction of the suspended dust particles will settle out within the plant boundaries and hence will contribute little to offsite particulate matter ambient air concentrations.

TABLE 70. PRINCIPAL RESOURCES COMMITTED TO PLANT OPERATION

Resource Category	Quantity	Normalized Quantity (Output)*
Land	440 acres	0.07 acre/MM Btu/hr**
Feedstock Coal	6.725 MM tons/yr	163.8 lb/MM Btu
Auxiliary Fuel (Vehicle)	100,000 gal/yr	134 Btu/MM Btu
Power	0	0
Water (1,925 gpm)	910.6 MM gal/yr	11.1 gal/MM Btu
Catalyst and Chemicals (Bechtel Estimate)	2,900 tons/yr	0.071 lb/MM Btu
Manpower (Bechtel Estimate-738 Employees)	1.56 MM manhours/yr	0.019 manhour/MM Btu

*Basis: 82.125 trillion Btu/yr HHV net output.

**Increases to 0.14 acre/MM Btu/hr if 440 acres buffer zone included.

HYGAS

TABLE 71. ESTIMATE OF ANNUAL HYGAS CHEMICAL REQUIREMENTS — BECHTEL ESTIMATE

Material	Quantity
All Process Catalysts	400 tons/yr
All Process Solvents	500 tons/yr
Water Treatment Chemicals	2,000 tons/yr
Dust Suppression Agent	5,000 gal/yr
Diesel and Gasoline Fuels	100,000 gal/yr

TABLE 72. SUMMARY OF ESTIMATED AIR EMISSIONS — HYGAS

Source	Flow Quantity	Pollutants	Emission Rate
Rail Car Dump (wet suppression)	3,000 tph 24,000 tpd (6 days)	Fugitive coal dust (0.05 lb/tpd)	1200 lb/day
Coal Stackers (wet suppression)	3,000 tph 24,000 tpd (6 days)	Fugitive coal dust (0.05 lb/tpd)	1200 lb/day
Coal Reclaimer (wet suppression)	853 tph 28,472 tpd	Fugitive coal dust (0.05 lb/tpd)	1000 lb/day
Dead Storage Pile, 60 days (sealed)	1,230,000 tons, 16 acres	Fugitive coal dust (0.01 lb/ton/mo)	400 lb/day
Live Storage Pile, 14 days (wet suppression)	286,600 tons 8 acres	Fugitive coal dust (0.1 lb/ton/mo)	1000 lb/day
Coal Preparation Vent Gases (after scrubber)	853 tph 48,000 CFM air	Fugitive coal dust (0.05 gr/CF)	165 lb/day
Acid Gas Removal CO_2 Vent Gases (2)	283,750 SCFM	H_2	31.4 lb/hr
		CO	759 lb/hr
		CH_4	3220 lb/hr
		C_2H_6	6240 lb/hr
		H_2S, COS	Small amounts
		Potentially toxic organics	Trace amounts
Sulfur Plant Tailgas(1)	499,730 SCFM, (includes 470,065 SCFM flue gases from boilers - 2186 MM Btu/hr input)	Particulate matter (99.5% reduction)	74 lb/hr
		SO_x	1056 lb/hr
		NO_x(0.2 lb/MM Btu)*	437 lb/hr
		CO(0.02 lb/MM Btu)*	44 lb/hr
		HC(0.01 lb/MM Btu)*	22 lb/hr
		H_2S, COS	Small amounts
Dehydration Vent Gas(2)	164 SCFM	CH_4	32 lb/hr
O_2 Plant Nitrogen Vent	91,500 SCFM Nitrogen	None	—

(Continued)

TABLE 72. (Continued)

Source	Flow Quantity	Pollutants	Emission Rate
Cooling Tower	917,200 SCFM dry air 404,766 lb/hr water vapor	Drift(water droplets)	5,124 lb/hr
		Salts(2000 mg/1)	10 lb/hr
		Chemicals**	3.4 lb/hr
		Thermal	359 MM Btu/hr
Flare	Normally no process emission, except for pilot gas combustion	Sulfur compounds	small amounts
		Hydrocarbons	small amounts
Misc. Process Areas		Fugitive hydrocarbons	small amounts
Plant Areas		Fugitive dust	small amounts
Fuel Storage		Hydrocarbons	small amounts
Vehicle Exhausts		Combustion products	small amounts

*Assumed emission factors.

**Chemical additives in the circulating water include sulfuric acid, a proprietary dispersant, a proprietary corrosion inhibitor and a biocide (shock chlorination).

The coal preparation facilities (crushing) will employ a venturi scrubbing system to remove coal dust from vent gases prior to release. Vent gas PM concentration was estimated at 0.05 grain per cubic foot.

Substantial quantities of gaseous pollutants will be released from two process sources, the CO_2 vent gas and the sulfur plant tail gas. Both will have a fairly high volumetric flow. The carbon dioxide-rich vent gases from the acid gas removal plants (two trains of Selexol) will contain approximately 600 ppmv of CO, 4470 ppmv of CH_4, and 4670 ppmv of C_2H_6 along with small amounts of reduced sulfur compounds (COS and H_2S). Trace concentrations of other hydrocarbons that may be classified as toxic or hazardous may also be present. Potentially, the CO_2 vent gases may need further cleanup before release.

The sulfur plant tail gas will contain approximately 12 tons per day of sulfur dioxide discharged to the atmosphere through a stack. More than 95 percent of the sulfur present in the feed coal and more than 99.8 percent of the feed sulfur to the sulfur plant will be captured, including SO_2 in the boiler flue gases. The sulfur oxide concentration in the tail gas, as designed, will exceed the federal NSPS for sulfur recovery units in the Petroleum Refining point-source category. Some small amounts of reduced sulfur compounds (COS and H_2S) are also likely to be present in the tail gas. Additional gas cleanup may be required for this stream, also.

Vent gas from product gas dehydration (two trains) will be composed of water vapor and about seven percent volume methane. The volumetric flows will be small, so that this is a minor source of hydrocarbon release.

Other point sources in the HYGAS facility will release rather small amounts of air pollutants. The cooling tower will discharge water vapor and heat. (Air coolers dissipate most of the process heat load.) Drift from the tower will contain salts and chemicals added to the circulating water. Organics and ammonia in the circulating water will also be carried out as dissolved constituents in the drift and perhaps as stripped vapors in the gaseous exhaust.

Fugitive hydrocarbons will also be released as leakage from valves, pumps, process vessels, and storage tanks. Plant areas will also be minor sources of windblown fugitive dust emissions. Combustion products from plant vehicles will probably be insignificant contributors to air pollution.

The HYGAS facility, as designed, would release hundred-ton-per-year quantities of fugitive dust, SO_2, NO_2, CO, and hydrocarbons. Overall, these pollutant releases at the hypothetical plant site would result in a small, adverse effect on ambient air quality in the area. It is likely that emission offsets (NO_2, CO, nonmethane hydrocarbons) will be needed to avoid significant deterioration as the site is located in a nonattainment area for carbon monoxide and photochemical oxidants.

Water Emissions--The conceptual plant, as designed (5,6), will not normally discharge any aqueous process effluent. Principal discharge pathways will be in water losses to the atmosphere and in water retained in the solid wastes. Internal recycle of process and water treating wastewater will minimize the plant makeup water demand (see Figure 24). Table 73 lists the plant's major aqueous streams and their dispositions. The wastewater treatment and reuse schemes described earlier indicate that most of the plant's waterborne contaminants will be routed to solids recovery and disposal. Estimates of pollutant concentrations in the internal recycle streams were not attempted.

Streams that are treated and routed to the circulating water system or makeup would be concentrated by the evaporation of water in the cooling tower. Any trace organics, ammonia, dissolved solids, and perhaps hydrogen sulfide may be present in appreciable concentrations in the cooling water. Fairly volatile compounds such as ammonia, H_2S, and some organics could be stripped partially into the exhaust air. The contaminants in high TDS streams routed to the flash evaporator will presumably be retained in the reject brine slurry and go out as a solid waste.

If upsets were to occur in the complex recycling systems, some aqueous streams might have to be routed temporarily to the storm basin, for later reprocessing or for discharge to the river. There is, hence, a potential for pollutant releases to the river.

Storm runoff from plant areas will constitute the only aqueous discharge from the conversion plant, and discharge will occur on an intermittent basis. A

TABLE 73. SUMMARY OF ESTIMATED WASTEWATER EMISSIONS — HYGAS

Source	Estimated Flow	Pollutants	Emission Rate
Gasifer Ash Slurry	647.8 gpm (routed to solids disposal)	Ash TDS	No aqueous emission
Quench Flashed Slurry	38.4 gpm (routed to solids disposal)	Ash TDS	No aqueous emission
Stripped Quench Condensate	1481.8 gpm (used as C.T. makeup)	BOD NH_3 H_2S pH	No aqueous emission
Stripped Shift Condensate (after biox treating)	1396.9 gpm (used as coal slurry makeup)	BOD(117 mg/l) Phenols(72 mg/l) NH_3 H_2S	No aqueous emission
Ammonia Recovery Effluent	169 gpm (used as C.T. makeup)	BOD NH_3 pH	No aqueous emission
Methanation Condensate	379.8 gpm (used as BFW makeup)	—	No aqueous emission
Lime Clarifier Sludge	38 gpm (routed to evaporator)	TSS pH	No aqueous emission
Filter Backwash	16 gpm (routed to evaporator)	TSS	No aqueous emission
Softener Regenerant Waste	64.6 gpm (routed to evaporator)	TDS	No aqueous emission
RO Filter Backwash and Brine	116 gpm (routed to evaporator)	TDS TSS pH	No aqueous emission

(Continued)

TABLE 73. (Continued)

Source	Estimated Flow	Pollutants	Emission Rate
Ion Exchange Regenerant Wastes (after neutralization)	47.7 gpm (routed to evaporator)	TDS pH	No aqueous emission
Boiler Blowdown	143.5 gpm (used as C.T makeup)	TDS* TSS pH	No aqueous emission
Cooling Tower Blowdown	123 gpm (routed to evaporator)	TDS* TSS pH	No aqueous emission
Sulfur Recovery Slurry	4.4 gpm (routed to solids disposal)	TSS NH_3	No aqueous emission
Sanitary Effluent (after treatment)	35 gpm (used for dust control and landscaping)	BOD TSS pH	No aqueous emission
Utility Wastewater (after settling)	200 gpm (routed to lime softener)	Oil & Grease TSS pH	No aqueous emission
Coal Yard Runoff (after settling)	27 gpm avg annual, intermittent flow-(normally routed to biox unit)	Oil & Grease (<10 mg/l) TSS (<50 mg/l) pH	< 3 lb/day < 16 lb/day 6 to 9
Plant Storm Runoff (after settling)	118 gpm avg annual, intermittent flow	Oil & Grease (<10 mg/l) TSS (<50 mg/l) pH	< 14 lb/day < 70 lb/day 6 to 9

*Includes chemical additives.

storm runoff basin will collect and settle drainage before discharge. Collected stormwater could also be used as plant makeup water, so that discharges to the river would occur only during heavy storm periods when the impoundment and workoff capacities were exceeded.

As designed (5), the live storage piles will be curbed with coal pile runoff directed to a sump for routing to the biological oxidation system. Runoff in excess of the sump pumping capacity and runoff from other areas including dead storage in the coal yard would go to another storm settling basin from which runoff would be discharged to the river.

The settled runoff (145 gpm average annual basis) will add some dissolved and suspended pollutants to the river, resulting in a minor degradation of water quality at times. Normally, with no aqueous discharge from the plant, there will be no impact on surface water quality. The average plant consumption of about 1925 gpm (0.4 percent of average river flow) will normally have little impact on downstream surface water availabilities, except during low river flow periods. Groundwater could potentially be affected by percolation through soils of pollutants from the storm basins or from the onsite solid waste landfill. The plant will not consume groundwater supplies directly. Overall, the plant will have little adverse impact on surface or groundwater qualities.

Solid Wastes--Ash material from the feed coal will constitute the bulk of the plant's solid waste production. Table 74 presents estimates of the major solid wastes and their disposition. Dewatered ash streams and sludge from the wastewater evaporator will be blended for transport back to the coal source strip mine. Pollutant characteristics of the blended solid wastes are not well known. It was assumed that burial in the strip mine would be environmentally acceptable. There is a potential that the wastes will be classified as hazardous and will require a more isolated disposal site.

If mine disposal were acceptable, waste burial under overburden at the mine site would help to offset the volumetric loss resulting from coal removal. On a tonnage basis (about 2390 tons per day), the net solid waste will be about 11.7 percent of the tonnage of coal shipped from the mine.

Digested and dewatered sludge from biological oxidation will contain potentially harmful organics (both dissolved and suspended). An onsite clay-lined landfill will be provided to bury this material along with a small amount of general plant trash and garbage. On the order of 58 to 60 acre-feet per year of waste will be emplaced onsite. Proper management of the land disposal operation will be needed to prevent contamination of groundwater and surface runoff. Incineration of the sludge and combustible plant trash could be considered as a method of reducing the volume of waste to be buried.

It is assumed that salvageable materials (scrap metals, spent oils, spent catalysts) will be shipped offsite for recovery. Other waste materials resulting from equipment cleaning or basin cleaning would likely be dewatered and buried onsite.

TABLE 74. SOLID WASTE DISPOSAL SUMMARY — HYGAS

Source	Estimated Quantity	Potential Pollutants	Disposal
Gasifier Ash (After Dewatering)	1,295.5 tpd solids 455.7 tpd water	Minerals, trace metals, alkalinity, suspended solids	Blended with other wastes, loaded into cars, shipped to mine for disposal
Quench Solids (After Dewatering)	50.4 tpd solids 12.6 tpd water	Minerals, trace, metals, organics, alkalinity, suspended solids	Blended with other wastes, loaded into cars, shipped to mine for disposal
Boiler Flyash from Sulfur Recovery	36 tpd solids 9 tpd water	Minerals, trace metals, alkalinity, suspended solids	Blended with other wastes, loaded into cars, shipped to mine for disposal
Bottom and Superheater Ash (After Dewatering)	180 tpd solids 48 tpd water	Minerals, trace metals, alkalinity, suspended solids	Blended with other wastes, loaded into cars, shipped to mine for disposal
Evaporator Solids (Blended with Ash)	19.2 tpd solids 283.7 tpd water	Inorganic solids, organics, heavy metals, suspended solids	Blended with other wastes, loaded into cars, shipped to mine for disposal
Biox Waste Sludge (Digested and Dewatered)	34.8 tpd solids 199.2 tpd water	Organics, NH_3, suspended solids (biological cell matter)	Buried in onsite landfill (clay-lined)
Plant Trash and Garbage	1,700 lb/day	Decomposable wastes and oily materials	Buried in onsite landfill (clay-lined)
Miscellaneous: Basin Cleanout Sludges Equipment Cleaning Sludges Spent Catalysts and Chemicals	Infrequently produced, no quantities estimated	-	Salvaged, or dewatered and buried onsite

Soils and Geology--Approximately 440 acres of land will be altered during construction and operation of the plant. Earthwork will include clearing and grading, cut-and-fill, and some excavation for basins and foundations. Additional offsite land will be affected by construction of rail spurs and access roads, transmission facilities, gas connector pipeline, water pipeline, and a discharge system. Solid waste will be burned at the mine site. Use of new surface materials for roadways and foundations will alter the surface characteristics of a portion of the site, but the undeveloped 440-acre buffer zone will be less affected and the overall regional impact will not be significant.

Biological Impacts--

Construction on 440 acres will affect primarily agricultural use. However, some prairie vegetation and wildlife will be removed or disturbed in fallow fields, along fence rows and roadways, and in isolated grasslands not converted to agriculture. Operation of the facility and increased traffic and human use, as well as construction activity, will likely disturb sensitive species nearby. However, careful site selection will ensure that no rare, endangered or important species or critical habitats will be affected, and, on a regional scale, this biological impact will be minor.

Secondary results related to construction will include damage to vegetation from dust or from erosion. Runoff from construction areas may also increase the sediment load in streams nearby, stressing sensitive aquatic biota. In addition, stream beds, farm ponds, or other aquatic habitat may be eliminated within the 440 acres by cut-and-fill activities.

The effect of SO_x and NO_x plant emissions on vegetation may be adverse downwind of the facility, particularly if the plume is forced to the ground by adverse meteorological conditions. In addition, salt from cooling-tower drift may accumulate in the soil downwind and damage sensitive vegetation.

Disposal of storm runoff wastewater to the river may cause a minor degradation in water quality which, in turn, could stress aquatic plants and animals in the vicinity of the discharge and downstream from the discharge point. In addition, the plant water intake and discharge system could entrain smaller aquatic animals; intake screens will prevent entrainment of fish and other large animals. No significant impact on river populations is expected from either of these activities, however.

Aesthetic Impacts--

The HYGAS plant will contrast markedly with the surrounding environment. The 280-foot-tall hydrogasification vessels, tall stacks, live and dead coal storage piles, rail yard, and coal handling facilities are not typical of the rural, agricultural nature of the area. In addition, contrasts in color of the coal piles against the surrounding countryside will serve to emphasize the differing nature of the facility. However, screening with trees, use of a 440-acre buffer zone, and plant design and layout can be used to minimize the visibility of the facility, reducing the impact in this farmland setting.

Social and Economic Effects

A portion of the $1.2 billion capital investment will be spent locally for equipment and materials. Labor and temporary jobs for about 3000 construction workers will be created. The increased regional income from these construction monies as well as the salaries and wages of more than 700 full-time employees will be a significant benefit to the economies of nearby towns. This additional income may also partially offset the demands for community goods and services caused by population increases in the region during construction.

Manpower for construction may be available in the region or through training programs, but temporary increases in population near the plant should be expected. These population increases will result in a proportional increase in demand for housing, schools, and other services which may be outside local abilities to provide. Plant management and local government may work together to provide planning, temporary housing, and services to reduce the impact of this demand.

The plant will consume approximately 134 Btu of fuels for each million Btu of gas produced, and coal feedstock at the rate of 127.4 lb/MM Btu. No purchased electricity will be consumed in gas production, although startup and shutdowns may require a small commitment of power for lighting, ventilation, electric motors, and other machinery. Use of coal as feedstock does constitute consumption of a nonrenewable resource and forecloses alternative uses of that resource. The plant, however, will generate a clean fuel in the form of synthetic gas, which offsets other consumptive uses.

Table 75 summarizes the principal environmental effects anticipated from construction and operation of HYGAS.

TABLE 75. SUMMARY ENVIRONMENTAL MATRIX — HYGAS

Environmental Factors	Effect of Plant Construction and Operation	Potential Mitigating Measures
Climatology and Meteorology	Potential fogging from cooling tower during periods of high humidity — local	
Air Quality	Fugitive dust-coal; HC, CO, NO_x, SO_x emissions; salts from cooling tower drift during operation. Fugitive dust and vehicle emissions during construction	
Surface Water Availability	About 12 gal/MMSCF required (or 11 gal/MM Btu) — no significant effect on water supply	
Surface Water Quality	Releases of sediment during construction as result of erosion; releases of small quantities of oil, grease, TSS during operation — local weather quality degradation	
Groundwater Availability	No consumption, no effect	
Groundwater Quality	Potential degradation from leaching of coal piles, solid waste landfill, waste ponds	Line ponds, proper management of landfills, pads under coal piles
Land Availability	880 acres of agricultural land-insignificant regional	Care in siting to prevent use of prime land (for agriculture) as site
Regional Ecology and Critical Habitat	440 acres of vegetation, wildlife — insignificant in region	Care in siting to avoid critical lands, rare or endangered species, etc.

(Continued)

TABLE 75. (Continued)

Environmental Factors	Effect of Plant Construction and Operation	Potential Mitigating Measures
Aesthetic Resources	Tall massive structures, color contrast of coal with surrounding soil and vegetation — moderate local aesthetic impact	Landscaping, plant layout and design, buffer zone of 440 acres
Historical, Archaeological Resources	No significant impact	Care in siting
Community Economy	Substantial benefit from capital expenditures, wages, tax base	
Community Population and Services	Potential increase in demands, population during construction	Community — plant coordination in planning temporary housing, services
Labor Availability	3000 construction and more than 700 permanent employees may be available from regional labor pool	Training programs for unskilled labor pool
Power Availability	No electricity consumption planned under normal operating conditions; power consumed during construction	
Transportation Availability	Build pipeline, rail spur, access road	

SECTION 5

SCENARIO 3 - WOOD AND COAL TO FUEL IN NORTHEAST REGION

In this scenario, a 2000 tpd wood liquefaction plant and a 25,000 tpd coal liquefaction (H-Coal) plant are to be constructed and operated at different, but similar, sites in the northeast region of the U.S. Figures 26 and 27 indicate the biomass and coal conversion regional locations. Separate regional environmental settings and hypothetical plant site descriptions are presented.

Plant feedstocks are assumed to be procured locally: forest residue from mills and forestland and coal from deep mines. Both plants produce a heavy fuel oil assumed to be suitable for firing in a steam electric generating plant without the need for flue gas desulfurization. The costs for products transported offsite (pipeline, truck, rail) are excluded. The wood-to-oil plant purchases electric power. As in the Fluor commercial evaluation report (7), the H-Coal plant has onsite power generation using process fuel gas. The H-Coal conceptual design (7) assumes offsite landfill disposal of solid wastes (conversion residues) for a contract disposal charge. An aqueous waste disposal charge is also assumed in the cost estimate (7); however, additional onsite waste treatment would be a more realistic assumption.

Principal environmental assumptions are:

- Proposed NSPS for steam-electric generating will apply
- Process fuel gas for combustion will have $\leq$0.10 gr/dSCF
- BACT for aqueous effluents will apply
- Conversion residues are assumed to be nonhazardous
- Preconstruction and emission offset environmental costs are excluded
- Product distribution costs and distribution impacts are excluded

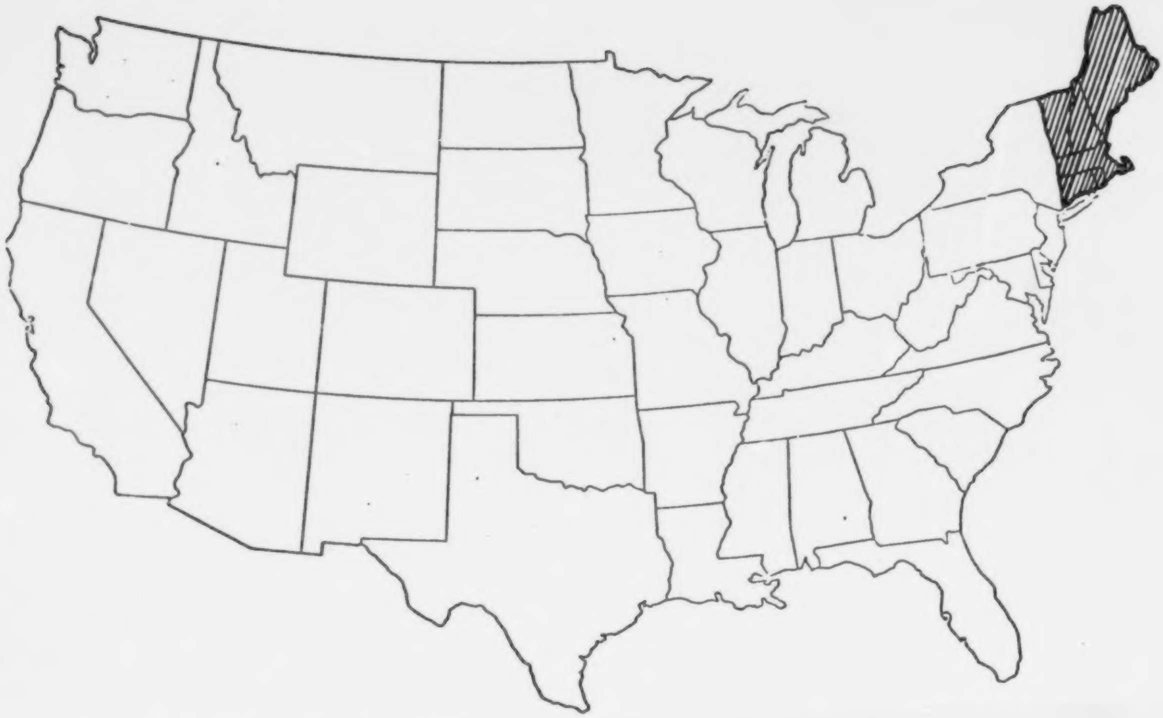

Figure 26. Wood to fuel oil region — Scenario 3.

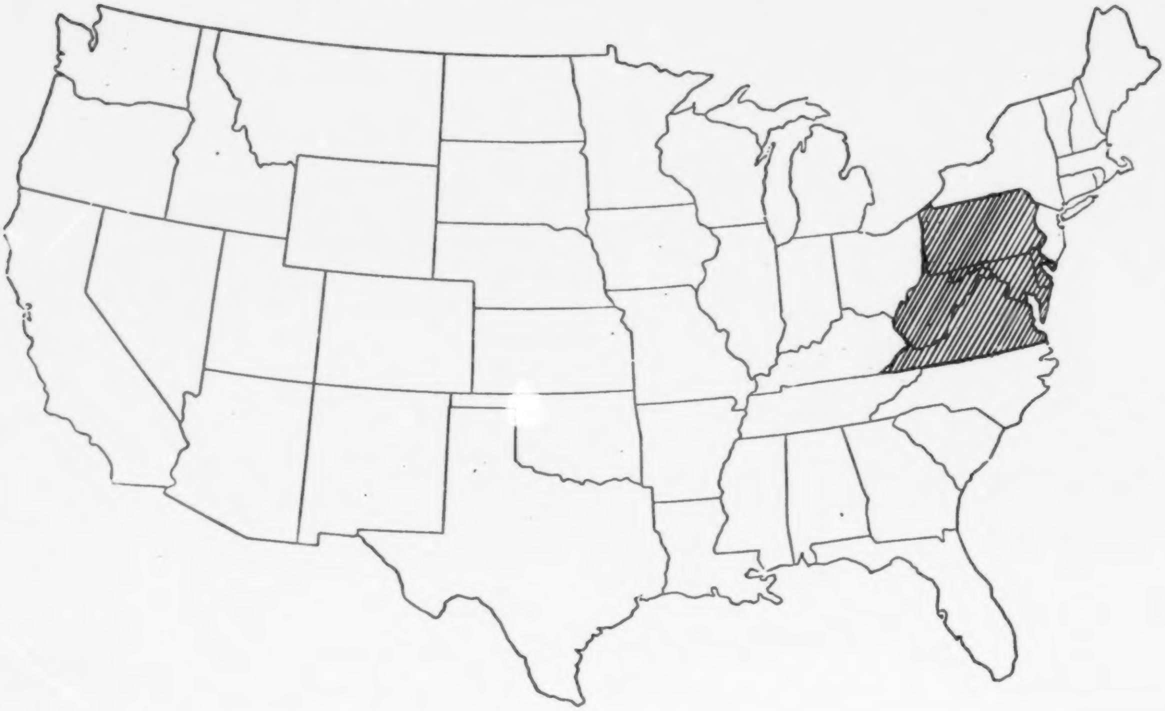

Figure 27. Coal to fuel oil region — Scenario 3.

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REGIONAL ENVIRONMENTAL SETTINGS

Biomass

The biomass conversion plant is located at a hypothetical location in the New England Region of the U.S. The following describes the environmental setting of this region.

Land Use--
Approximately 77 percent of New England land is in forest. Only 31 percent of land area is cultivated, of which less than a fourth is in crops. About one-tenth of the region is urban, but this is increasing rapidly, especially in the south. Extensive agriculture has given way to intensive farming such as dairying, potatoes, tobacco, blueberries, and cranberries. Greenhouse and open-field vegetables are grown near big towns and cities (16). Most of the forest is in small holdings in farm woodlots. Lumber is the principal product. The woodland is widely used for hunting and other recreation. Christmas trees and maple syrup are other important products.

Topography and Elevation--
Topographically the region has four major divisions: mountains, upland plateau, lowland plain, and ridge and valley. Much of the area is between sea level and 1000 feet. Low hills up to 2000 feet are common but a few peaks of around 3000 feet do occur. The northeastern mountains have a few isolated peaks of more than 5000 feet. The till-mantled rolling to hilly uplands are interrupted by many level-to-gently-sloping valleys that slope toward the coastal lowlands. The relief is mostly in a few feet to a few tens of feet in the valleys and in several tens of feet to a few hundred feet in the uplands.

Climate--
New England receives rainfall which is well distributed and makes possible the production of crops suited to temperate regions. The annual rainfall varies from 50 inches in southern New England to less than 32 inches in the extreme north. Prevailing temperatures vary between 67°F average in summer and a winter average of 20 to 30°F. The average growing season varies from 100 to 125 days in the extreme north to some 200 days in the southern part (13, 14, 16, 36).

Soils--
Spodisols dominate the New England soils, but Inceptisols and Alfisols are found in the western portion of the area. The Spodisols have a low supply of bases and a horizon in which organic matter and iron and aluminum compounds have accumulated (16).

Vegetation--
Many kinds of forest vegetation are found in New England. In the north the most important commercial forests are of spruce (*Picea spp.*) and the balsam fir (*Abies balsamea*) — the spruce-fir ecosystem. Other associates include northern white-cedar (*Cedrus spp.*), tamarack (*Larix laricina*), maple (*Acer spp.*), birch (*Betula spp.*), eastern hemlock (*Tsuga canadensis*), and eastern white pine (*Pinus spp.*)(14).

The northern hardwoods, or maple-birch-beech ecosystem, typically occur on open high hills and low mountains on ridges rising 500 to 3000 feet above the broad valleys. Common associates of the ecosystem include hemlock, elm (*Ulmus spp.*), basswood (*Tilia spp.*), and white pine (14).

Wildlife--

The fauna of the spruce-fir ecosystem include moose, woodland caribou, lynx, marten, black bear, long-tailed weasel, mice, and shrews. The ruffed grouse is common and the wild turkey occurs to the south of the area. The eastern timber wolf is an endangered species resident in this forest type (16).

The white-tailed deer occurs throughout the northern hardwoods ecosystem, utilizing the farmed areas for food. The black bear is also common and the red and grey foxes are also widespread. Several species of squirrel and mice are found in this ecosystem. Common birds include the ruffed grouse, the bobwhite, and several songbirds.

H-Coal

The H-Coal conversion plant is located at a hypothetical location in the eastern region of the U.S. The following describes the environmental setting of this region.

Land Use--

The area is located in the east and central general farming and forest region, the central feed grains and livestock region, the northeastern forage and forest region, and the Atlantic and Gulf Coast lowland forest and truck crop region of the U.S. The major land use is cropland, with interspersed patches of forest, woodland, and pasture. The eastern (coastal) portion of the area is heavily urbanized; the more undeveloped areas are found primarily at the higher elevations of the Appalachian Mountains (22).

Topography and Elevation--

Elevation ranges from sea level to 5000 feet above sea level, with the higher elevations being located in the Appalachian, or Eastern, Highlands. The coastal plains dominate the eastern part of the area while the open hills and low mountains dominate the west. The majority of the land is gently sloping, with local relief ranging from 0 to 100 feet in the plains and 1000 to 3000 feet in the hills.

Climate--

The eastern area receives between 32 and 64 inches a year of precipitation; the highest rainfall coincides with the areas of higher elevation, but, in general, the rainfall is evenly distributed throughout the region. Prevailing temperatures range from a summer average of 80°F to a winter average of 35°F. Cooler temperatures prevail in the highlands. The average growing season varies from 120 to 150 days per year (22).

Soils--

The major soils in the eastern region are Ultisols, Inceptisols and Alfisols, but the soil associations vary widely. Some have subsurface horizons of accumulated clays and salts but are typically low in bases (16).

Vegetation--

The dominant ecosystem types are Appalachian oak, northern hardwoods, and oak-hickory-pine forests. Higher elevations in the Appalachians may support a northeastern spruce-fir forest, and river drainages near the coast are typically southern floodplain forest. The most important tree species are:

- White oak *(Quercus alba)* and northern red oak *(Quercus)* in Appalachian oak forests, with maples *(Acer spp.)*, birch *(Betula lenta)*, hickories *(Carya spp.)*, beech *(Fagus grandifolia)*, and the tulip tree *(Liriodendron tulipifera)* well represented
- Sugar maple *(Acer saccharum)*, yellow birch *(Betula allegheniensis)*, beech and hemlock *(Tsuga canadensis)* in northern hardwoods, with pines also represented
- Hickory, shortleaf pine *(Pinus echinata)*, loblolly pine *(P. taeda)*,white oak *(Q. stellata)* in oak-hickory-pine forests

Wildlife--

Dense, mixed forests support deer, small mammals (raccoon, squirrel, chipmunk, mice, and voles), small birds (titmouse; bluejay; redbellied, hairy, and downy woodpeckers), hawks, and owls. Typical forest reptiles (garter snake, black racer, timber rattlesnake, box turle) may also occur (37). Other important species include black bear, bobcat, grey fox, grouse, bobwhite, mourning dove, and turkey (16).

WOOD-TO-OIL PLANT SITE DESCRIPTION

The biomass conversion plant is located in a hypothetical forested rural area in the Eastern Uplands approximately one-half mile east of a major river in the region.

Topography and Elevation

Rolling hills rise to about 700 feet in elevation in the vicinity. The plant site is on a gently sloping terrain above the flood plain at about 400 feet in elevation and about 100 feet above the normal river water level.

Transportation

A state highway and a common carrier rail line each pass within one mile of the plant site. Another state highway across the river to the west is about two miles from the plant. Several small towns are nearby, located on either side of the river. The nearest city (about 42,500 population) is about 10 miles downstream and has additional road and rail transportation.

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Climate and Air Quality

The climate in the site area is cool and humid, characterized by long cold winters and short cool to warm summers, moderated by the Atlantic Ocean. Great variations in seasonal and diurnal temperatures are a common phenomenon. Rainfall is ample (43 inches, including the water equivalent of snow) and is evenly distributed. The sky is cloudy about half the time and partly cloudy 16 percent of the time. Relative humidity ranges from 71 percent in March to 79 in November with a yearly average of 75. The prevailing winds are northwesterly or northeasterly in winter and southwesterly in summer. Hurricanes or damaging rains are rare.

The average length of the freeze-free season ranges from approximately 130 days in the north part of the county to 170 days in the more protected areas.

The number of thunderstorms varies from year to year. An average of 15 to 20 may be expected annually from May through August. Most of them are not damaging to crops. Generally, hailstones fall only about once or twice a year, usually in spring or summer thunderstorms. Heavy rains accompanying the more severe thunderstorms sometimes injure crops and erode soils (38). Table 76 shows assumed climatic data at the site.

TABLE 76. ASSUMED CLIMATIC CONDITIONS AT THE SITE

Elevation = 400 feet	p = 29.5 Hga
Temperature:	
Annual Average	44°F dry bulb 40°F wet bulb
5-Percent Design Conditions	83°F dry bulb 70°F wet bulb
Annual (daily) Extremes	-20°F to 95°F
Prevailing Wind:	Eastsoutheast at three mph
Precipitation:	
Annual Precipitation	43 inches
Annual Runoff	25 inches
Annual Lake Evaporation	23 inches
10-yr, 24-hr Duration Storm	4.5 inches
Annual Freeze Free Period:	150 days

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Air quality in the vicinity of the plant is generally good; however, the air quality region is currently listed as a nonattainment area for photochemical oxidants.

Land Use

The site is primarily used as forestland in private ownership. A small portion near the river is currently in use as pastureland.

Water Resources

River flow at the plant averages 6104 cfs with a minimum annual (daily) discharge of 2100 cfs. Water quality is very good; both dissolved solids and hardness levels are low (see Table 77). The mean annual temperature of the river water is 50°F with a 32°F to 75°F daily annual average. All of the plant's water makeup will be supplied by the river.

Soils

Soils of New England have developed in a cool humid climate under forest. The major soil groups are classified as gently sloping Haplorthods and Fragiothods (Order Spodosol, suborder Orthods), Haplaquepts (Order Inceptisols, suborder Aquepts), and Planosols (27).

The subject soils range from well or excessively drained to very poorly drained. In general, better drained soils are on the higher lands and poorly drained soils on lower slopes or in depressions. Soils on glacial till often are hilly and have complex slopes; those from granitic till usually are extremely stony, acid, and sandy. The soils are generally shallow in steeply sloping areas and are in forest. Erosion is not a serious problem since 70 percent of the area is forested.

Vegetation

Two-thirds of the land in the vicinity of the plant is woodland. Timberland is the most important resource in the area. The bulk of the wood is used by the pulp and paper industry, which is well established in the area.

Mixed hardwoods, sugar maple, red maple, beech, and ash are prevalent in the site area, particularly on the well-drained till soils and the associated upland soils. The stands are interspersed with hemlock, white birch, and white pine. White pine occurs as pure stands on farmland that has reverted to forest. It also grows well on sandy and gravelly soils in the river valley where competition from hardwoods is less severe. Hemlock maintains itself among hardwoods and in areas never cleared for farming. White birch is also important, particularly in areas once clear cut or on burnt-over land.

Wildlife

The site area is rich in wildlife. Woodland species include ruffed grouse, woodcock, thrush, vireo, scarlet tanager, gray squirrel, red squirrel, white-tailed deer, raccoon, snowshoe hare, and other kinds of birds and mammals. Wetland

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TABLE 77. ASSUMED RIVER WATER QUALITY AT THE SITE — AVERAGE

Component	Value
Flow, Average Discharge	6,104 cfs
Flow, Minimum Annual	2,100 cfs
pH	6.7
Temperature	50^{o}F
Dissolved Oxygen	11 mg/l
Alkalinity (as $CaCO_3$)	13 mg/l
Bicarbonate Alkalinity (as HCO_3)	16 mg/l
Carbonate Alkalinity (as CO_3)	0 mg/l
Calcium and Magnesium Hardness	19 mg/l
Noncarbonate Hardness	6 mg/l
Total Dissolved Solids	48 mg/l
Calcium	5.8 mg/l
Magnesium	0.9 mg/l
Sodium	7.5 mg/l
Potassium	0.9 mg/l
Chloride	9.6 mg/l
Sulfate	8.5 mg/l
Fluoride	0.2 mg/l
Silica	4.9 mg/l
Phosphorus	0.04 mg/l
Nitrate	0.21 mg/l
Nitrite	0.01 mg/l
Iron, Total	0.53 mg/l
Manganese	0.04 mg/l

wildlife includes black duck, wood duck, rail, heron, shore birds, mink, muskrat, beaver, and other kinds of birds normally living in ponds, swamps, and marshes (38, 39). A large herd of moose is found in the northwestern part of the county. Moose are protected animals.

FOREST RESIDUE PROCUREMENT

Approximately 650,000 tons (wet) per year of wood chips and bark would be consumed by the wood-to-oil conversion plant. On the order of 360,000 tons (dry) per year of logging and collected forestry waste are located within 32 mean transport miles of a power plant about 20 miles south of the conversion plant (18). About 900,000 (dry) tons per year are available in nine counties surrounding the conversion plant. Annual consumption would be about 40 percent of the waste reportedly available in the nine-county area. In this scenario, the conversion plant owner purchases wood waste delivered to the plant site. Mean transport distance is assumed to be 45 miles.

Most of the feedstock is purchased on a contract basis from independent producers and pulpwood dealers who harvest forestland, mainly in private ownership. Forest residues are collected and chipped on site by special crews either concurrent with conventional harvesting or during a later pass through the tract. The crews employ chain saws for cutting and stripping (in some cases stump-pullers for stump and root extraction) and dozer-tractors for movement of the waste to mobile wood chippers. Hand collection of smaller branches is also common. Chipped waste is blown into trailer trucks on the logging roads to the highway and thence directly to the plant or to concentration yards in the area.

The chipped residue is transloaded to rail hopper cars and large trailer trucks for shipment to the plant. Residue harvesting is somewhat seasonable with lower production in the winter and spring quarters of the year. The yarding operations provide surge storage to somewhat level the deliveries to the conversion plant over the year.

In this forestland area, the total biomass inventory is on the order of 100 (over dry) metric tons per hectare (44.6 tons/acre) of which some 40 to 45 percent may be classified as possible forest residue. Annual growth (whole tree) is about 3 MT/ha (1.3 tons/acre). At a minimum, some 20,600 acres of forestland would need to be completely harvested for residue each year.

WOOD-TO-OIL PROCESS DESCRIPTION

Summary

The wood-to-oil process design is based on the Pittsburgh Energy Research Center (PERC) conversion process now under development at the Biomass Liquefaction Experimental Facility in Albany, Oregon. In this scenario, the commercial plant converts about 2000 tons (1965 tons) per day of wood waste into about 1764 barrels per day of heavy fuel oil. A private company is assumed to be the owner and operator of this facility, which has a 20-year plant life. Wood chips and bark are purchased (at dollars per ton delivered) by the owner on a contract basis from loggers and mills in the region. One thousand tons per day of wood

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is used directly in the conversion process. Most of the remainder is used to generate gas (CO) for the wood-to-oil reduction reaction. A small amount is used to generate process steam. The heavy fuel oil product is shipped from the plant in heated tank trucks for use as a supplemental clean fuel by local utilities. Overall direct thermal efficiency is about 53 percent. The plant's boundaries are indicated by the fenced area in Figure 28.

The process description is divided into six sections — feedstock receiving and storage, feed preparation, reaction, product separation, syngas production, and auxiliaries. (See Figures 29 through 32). Two parallel (50 percent capacity) processing trains are provided for wood conversion and syngas production.

Design Basis

The wood-to-oil plant is based on a modification of the PERC process. Many parts of this conceptual design have not been demonstrated. Major design bases and assumptions made to define the process are summarized in Tables 78 and 79.

Feedstock Receiving and Storage

Wood chips and bark are shipped to the plant in rail hopper cars and in end-dump trailer trucks. A single 18,000-cubic-foot underground hopper dump receives chips from both hopper cars and trailer trucks. Rail cars and trucks are unloaded six days per week — an average of 2300 tons per day.

Bottom-dump hopper cars are unloaded automatically while being pulled across the rail hopper dump. Rail siding is available for full and empty cars. Truck trailers are raised and tilted by hydraulic platforms which allow the chips to flow into the hopper pit. The wood chip truck circuit in the plant is one-way with the trailers being weighed (gross and tare) at the plant gate (see Figure 29).

The dump hopper conveyor transfers chips onto a high-speed belt conveyor which delivers them to twin 10,000-cubic-foot surge bins. Chips from the bins are pneumatically conveyed to the outside chip storage pile through pipes lying on the surface of the pile. Conveyor capacity is 125 tons per hour each. The transfer pipes are moved periodically to build up depleted areas of the pile.

Normally a 60-day feedstock supply is maintained (120,000 tons, or 12 MM cubic feet). At an average of 30 feet, the base of the pile covers 9 to 10 acres of land. The stockpile is worked down somewhat during the winter months when logging operations are curtailed. An underpile reclaim system pulls chips from the pile bottom along its long axis, providing a fairly uniform feed (composite).

Auger conveyors, mounted on carriages, draw chips from the pile and discharge them onto two belt conveyors in an underground tunnel in the long axis. The two belt conveyors move the chips to the center of the tunnel where the chips are transferred to two parallel inclined belt conveyors. The inclined conveyors emerge from a tunnel beyond the base of the pile and terminate at the top of the transfer house. Each 30 inch-wide belt conveyor can supply 100 tons per hour of chips to the feed distribution system. The transfer house contains magnetic separators (tramp iron removal) and a series of transfer bins with

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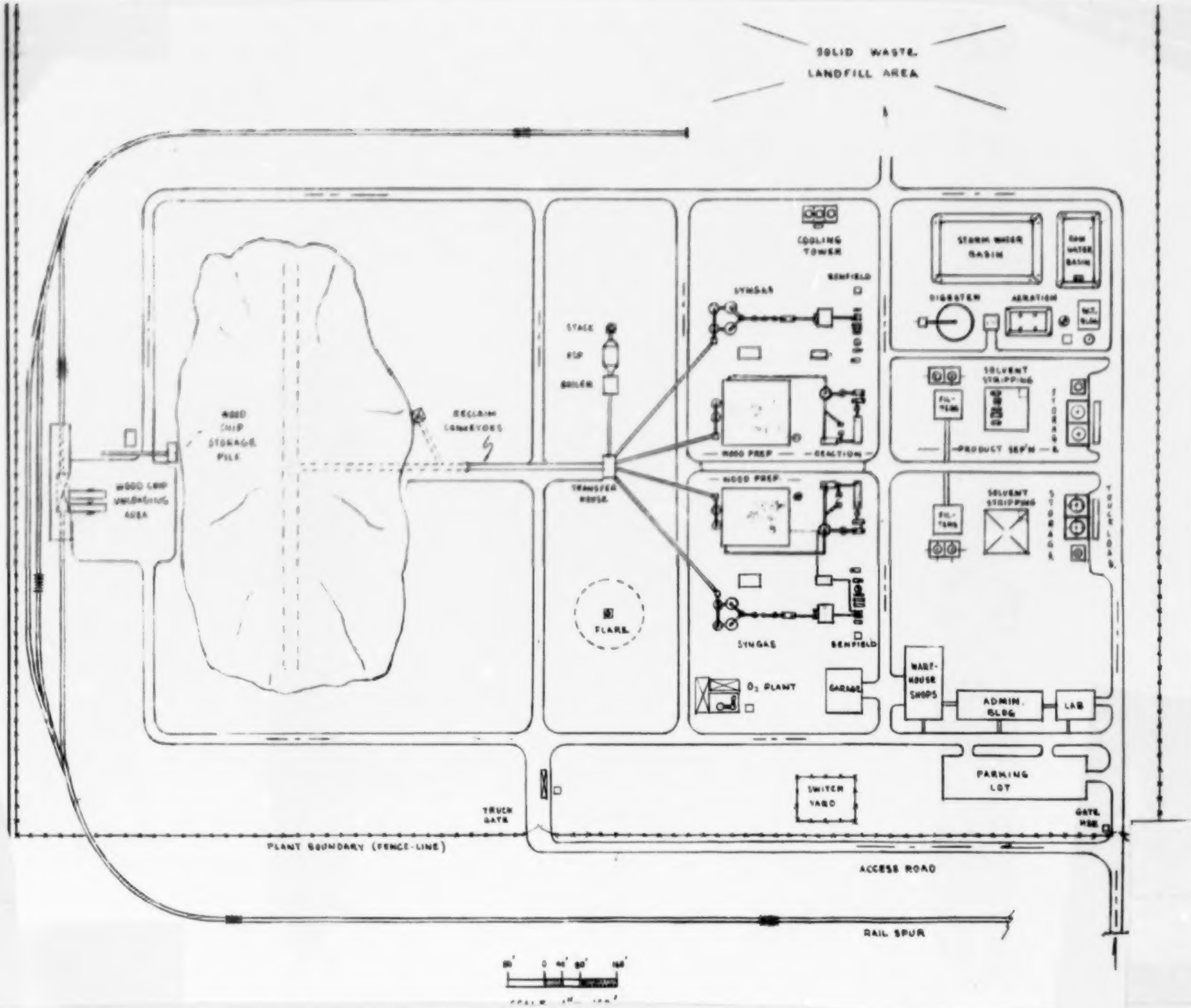
SOLID WASTE.
LANDFILL AREA
COOLING TOWER
STORM WATER BASIN
RAW WATER BASIN
DIGESTER
AERATION
W.T. BLDG.
BENFIELD
SYNGAS
WOOD PREP
REACTION
SOLVENT STRIPPING
FIL-TERS
STORAGE
PRODUCT SEP'N
TRUCK LOAD'G
STACK
ESP
BOILER
TRANSFER HOUSE
FLARE
O₂ PLANT
GARAGE
WARE-HOUSE SHOPS
ADMIN. BLDG
LAB
PARKING LOT
SWITCH YARD
GATE HSE
TRUCK GATE
WOOD CHIP STORAGE PILE
RECLAIM CONVEYORS
WOOD CHIP UNLOADING AREA
PLANT BOUNDARY (FENCE-LINE)
ACCESS ROAD
RAIL SPUR
80' 0 40' 80' 160'

Figure 28. Wood to oil plant, general arrangement.

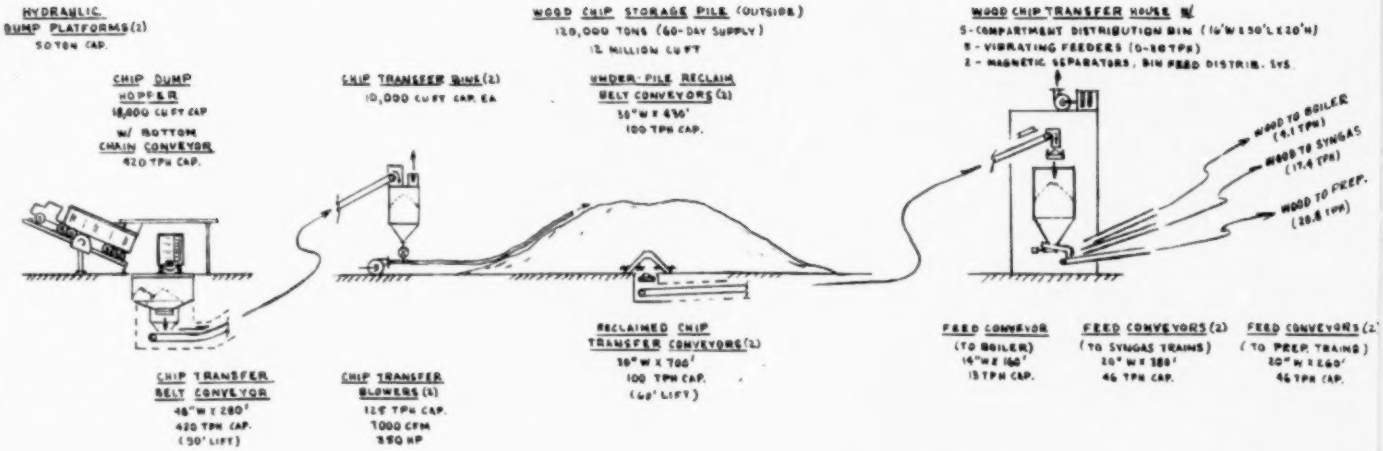
HYDRAULIC
DUMP PLATFORMS (2)
50 TON CAP.
CHIP DUMP
HOPPER
18,000 CU FT CAP
W/ BOTTOM
CHAIN CONVEYOR
420 TPH CAP.
CHIP TRANSFER BINS (2)
10,000 CU FT CAP. EA
WOOD CHIP STORAGE PILE (OUTSIDE)
120,000 TONS (60-DAY SUPPLY)
12 MILLION CU FT
UNDER-PILE RECLAIM
BELT CONVEYORS (2)
30"W x 430'
100 TPH CAP.
WOOD CHIP TRANSFER HOUSE W/
5-COMPARTMENT DISTRIBUTION BIN (16'W x 50'L x 20'H)
5 - VIBRATING FEEDERS (0-30 TPH)
2 - MAGNETIC SEPARATORS, BIN FEED DISTRIB. SYS.
WOOD TO BOILER (4.1 TPH)
WOOD TO SYNGAS (17.4 TPH)
WOOD TO PREP. (20.8 TPH)
CHIP TRANSFER
BELT CONVEYOR
48"W x 280'
420 TPH CAP.
(30' LIFT)
CHIP TRANSFER
BLOWERS (2)
125 TPH CAP.
7000 CFM
350 HP
RECLAIMED CHIP
TRANSFER CONVEYORS (2)
30"W x 700'
100 TPH CAP.
(60' LIFT)
FEED CONVEYOR
(TO BOILER)
14"W x 160'
13 TPH CAP.
FEED CONVEYORS (2)
(TO SYNGAS TRAINS)
20"W x 380'
46 TPH CAP.
FEED CONVEYORS (2)
(TO PREP. TRAINS)
20"W x 260'
46 TPH CAP.

Figure 29. Wood chip receiving and storage section (wood to oil).

1 2

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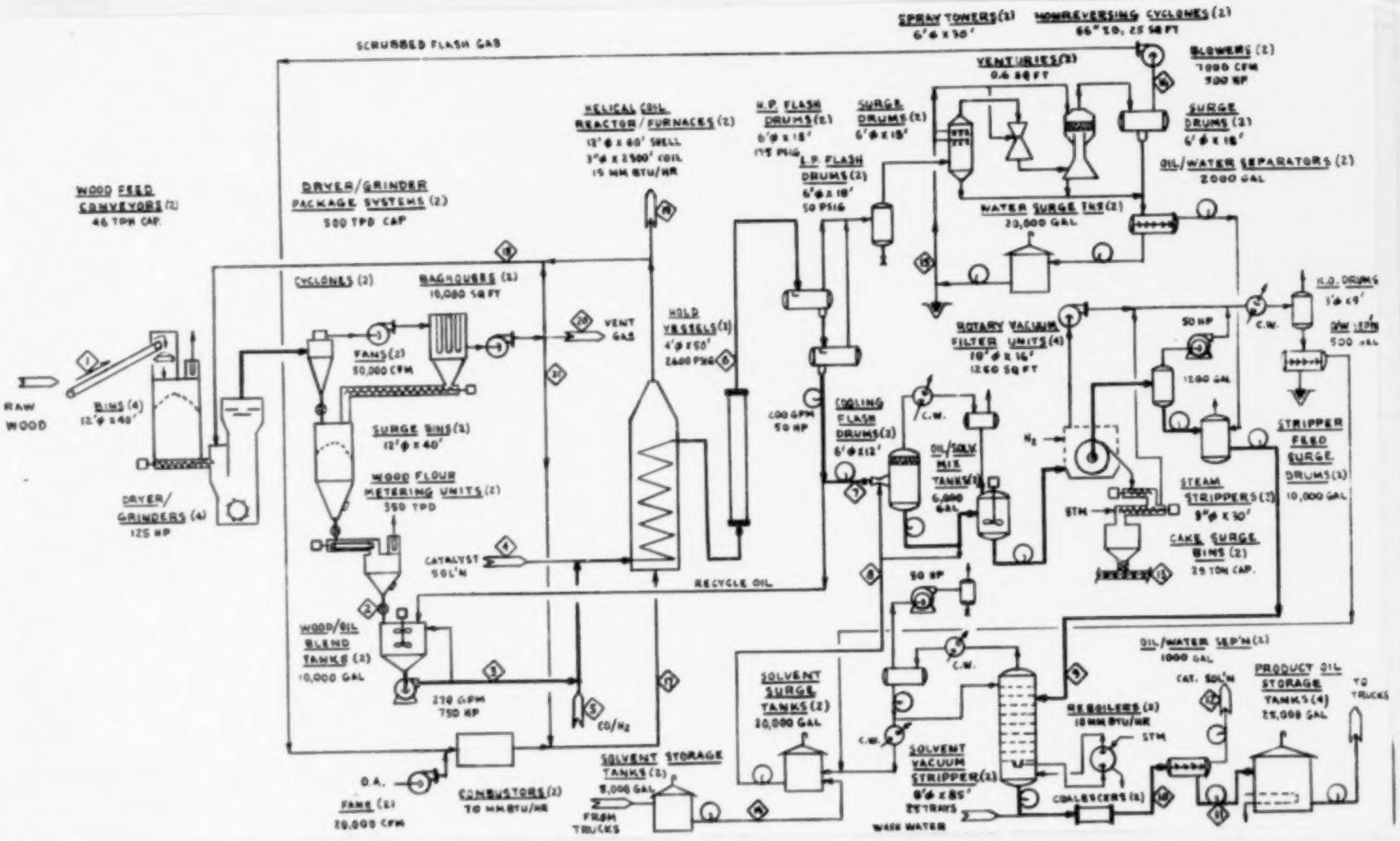
SCRUBBED FLASH GAS
WOOD FEED CONVEYORS (2)
46 TPH CAP.
RAW WOOD
BINS (4)
12'ϕ x 40'
DRYER/GRINDERS (4)
125 HP
DRYER/GRINDER PACKAGE SYSTEMS (2)
500 TPD CAP
CYCLONES (2)
FANS (2)
50,000 CFM
BAGHOUSES (2)
10,000 SQ FT
VENT GAS
SURGE BINS (2)
12'ϕ x 40'
WOOD FLOUR METERING UNITS (2)
350 TPD
CATALYST SOL'N
WOOD/OIL BLEND TANKS (2)
10,000 GAL
270 GPM
750 HP
CO/H2
O.A.
FANS (2)
20,000 CFM
COMBUSTORS (2)
70 MM BTU/HR
HELICAL COIL REACTOR/FURNACES (2)
12'ϕ x 60' SHELL
3"ϕ x 2500' COIL
15 MM BTU/HR
HOLD VESSELS (2)
4'ϕ x 50'
2600 PSIG
RECYCLE OIL
H.P. FLASH DRUMS (2)
6'ϕ x 18'
175 PSIG
L.P. FLASH DRUMS (2)
6'ϕ x 18'
50 PSIG
SURGE DRUMS (2)
6'ϕ x 18'
600 GPM
50 HP
COOLING FLASH DRUMS (2)
6'ϕ x 12'
SPRAY TOWERS (2)
6'ϕ x 30'
NONREVERSING CYCLONES (2)
66" ID, 25 SQ FT
VENTURIES (2)
0.6 SQ FT
BLOWERS (2)
7000 CFM
500 HP
SURGE DRUMS (2)
6'ϕ x 18'
OIL/WATER SEPARATORS (2)
2000 GAL
WATER SURGE TKS (2)
20,000 GAL
C.W.
OIL/SOLV MIX TANKS (2)
6,000 GAL
ROTARY VACUUM FILTER UNITS (4)
10'ϕ x 16'
1260 SQ FT
N2
50 HP
1200 GAL
STM
STEAM STRIPPERS (2)
9"ϕ x 30'
CAKE SURGE BINS (2)
25 TON CAP.
H.O. DRUMS
3'ϕ x 9'
O/W SEP'N
500 GAL
STRIPPER FEED SURGE DRUMS (2)
10,000 GAL
50 HP
SOLVENT STORAGE TANKS (2)
5,000 GAL
FROM TRUCKS
SOLVENT SURGE TANKS (2)
20,000 GAL
SOLVENT VACUUM STRIPPER (2)
8'ϕ x 85'
25 TRAYS
WASH WATER
OIL/WATER SEP'N (2)
1000 GAL
REBOILERS (2)
10 MM BTU/HR
COALESCERS (2)
CAT. SOL'N
PRODUCT OIL STORAGE TANKS (4)
25,000 GAL
TO TRUCKS
1
2
3
4
5
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Figure 30. Wood to oil process flow diagram — preparation, reaction, and product recovery.

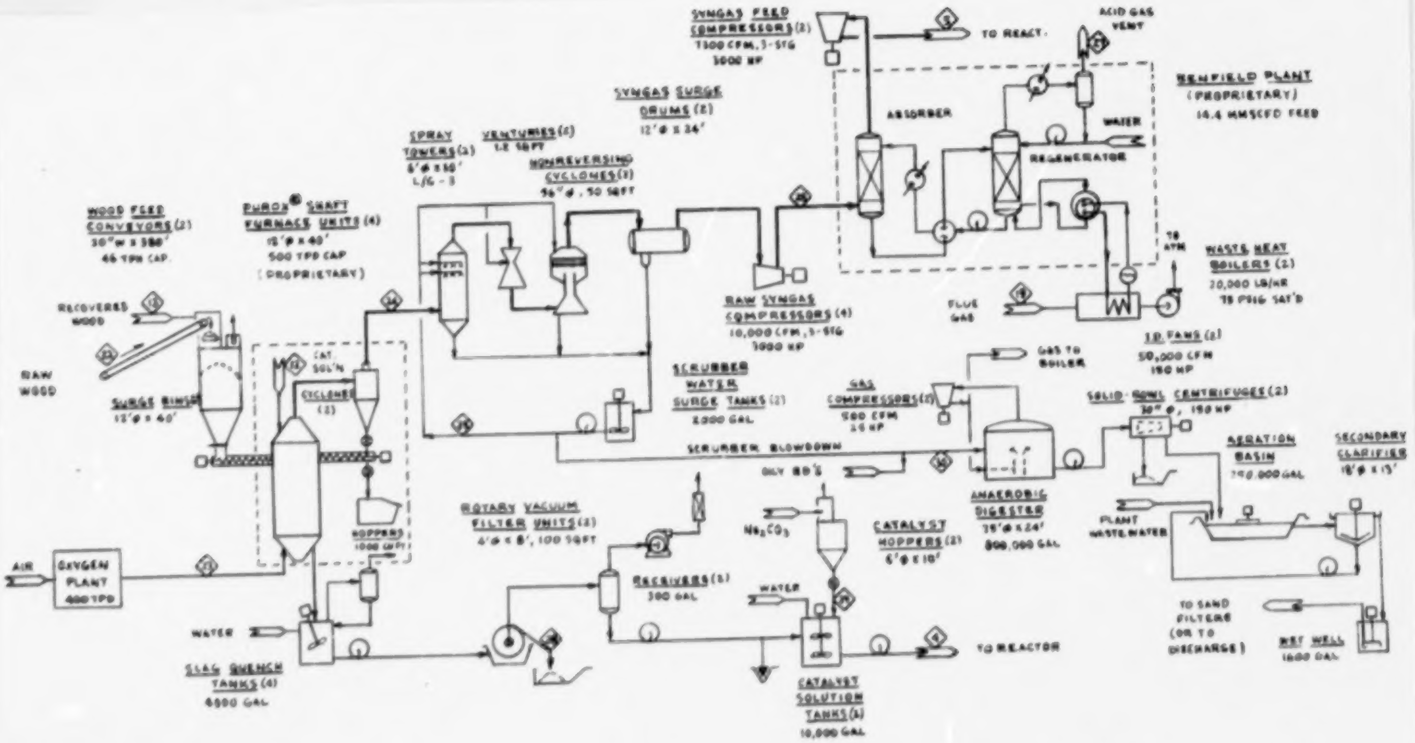
WOOD FEED CONVEYORS (2)
30"W x 380'
46 TPH CAP.
PUROX® SHAFT FURNACE UNITS (4)
12'φ x 40'
500 TPD CAP
(PROPRIETARY)
SPRAY TOWERS (2)
6'φ x 30'
L/G - 3
VENTURIES (2)
1.2 SQFT
NONREVERSING CYCLONES (2)
56"φ, 50 SQFT
SYNGAS SURGE DRUMS (2)
12'φ x 24'
SYNGAS FEED COMPRESSORS (2)
7300 CFM, 3-STG
3000 HP
TO REACT.
ACID GAS VENT
ABSORBER
WATER
REGENERATOR
BENFIELD PLANT
(PROPRIETARY)
14.4 MMSCFD FEED
RECOVERED WOOD
RAW WOOD
SURGE BINS (2)
12'φ x 40'
CAT. SOL'N
CYCLONES (2)
HOPPERS
1000 (FT³)
AIR
OXYGEN PLANT
400 TPD
WATER
SLAG QUENCH TANKS (4)
6500 GAL
RAW SYNGAS COMPRESSORS (4)
10,000 CFM, 3-STG
3000 HP
SCRUBBER WATER SURGE TANKS (2)
2000 GAL
SCRUBBER BLOWDOWN
FLUE GAS
TO ATM
WASTE HEAT BOILERS (2)
20,000 LB/HR
75 PSIG SAT'D
I.D. FANS (2)
50,000 CFM
150 HP
GAS TO BOILER
GAS COMPRESSORS (2)
500 CFM
25 HP
OILY BD'S
ANAEROBIC DIGESTER
35'φ x 24'
800,000 GAL
SOLID-BOWL CENTRIFUGES (2)
30"φ, 150 HP
AERATION BASIN
190,000 GAL
SECONDARY CLARIFIER
18'φ x 15'
PLANT WASTEWATER
ROTARY VACUUM FILTER UNITS (2)
4'φ x 8', 100 SQFT
RECEIVERS (2)
300 GAL
Na_2CO_3
CATALYST HOPPERS (2)
6'φ x 10'
WATER
CATALYST SOLUTION TANKS (2)
10,000 GAL
TO REACTOR
TO SAND FILTERS (OR TO DISCHARGE)
WET WELL
1600 GAL

Figure 31. Wood to oil process flow diagram — syngas production and catalyst recovery.

DESCRIPTION / COMPONENT	1 RAW WOOD TO DRY/GRIND	2 DRY WOOD TO BLENDER	3 WOOD/OIL SLURRY TO REACTOR	4 CATALYST SOLUTION TO REACTOR	5 COMPRESSED SYNGAS TO REACTOR	6 REACTION PRODUCT TO FLASH TANKS	7 RAW OIL TO PRODUCT SEPARATION	8 DILUENT SOLVENT RECYCLE	9 OIL/SOLVENT FILTRATE TO STRIP.	10 STRIPPER BOTTOMS TO O/W SEP'N	11 PRODUCT OIL TO STORAGE	12 RECOVERED CATALYST TO SYNGAS	13 RECOVERED WOOD TO SYNGAS	14 DILUENT SOLVENT MAKEUP	15 FLASH GAS SCRUBBER SPRAY WATER
PRESSURE, PSIA	14.5	14.7	2500	3500	4000	600	50	30	50	50	30	45	15	30	45
TEMPERATURE, °F	60	100	400	108	420	650	515	180	150	180	180	180	160	60	80
H_2, M LB/HR	-	-	-	-	0.826	0.826	-	-	-	-	-	-	-	-	-
H_2O, "	18.750	2.546	2.546	1.402	0.026	3.974	-	-	-	1.402	trace	1.402	-	-	50.000
N_2, "	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CO, "	-	-	-	-	15.055	4.292	-	-	-	-	-	-	-	-	-
O_2, "	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CO_2, "	-	-	-	-	0.125	17.036	-	-	-	-	-	-	-	-	-
OIL, "	-	-	60.223	-	-	75.610	15.377	-	15.377	15.377	15.377	-	-	-	-
SOLVENT, "	-	-	-	-	-	-	-	31.794	31.731	-	-	-	0.021	0.063	-
WOOD ($C_6H_9O_4$), "	22.619	22.619	26.907	-	-	9.381	1.094	-	-	-	-	-	1.094	-	-
INERTS (N_2+ASH), "	0.298	0.298	1.465	-	-	1.465	0.298	-	0.058	0.058	0.058	-	0.360	-	-
Na_2CO_3, "	-	-	1.312	0.350	-	1.722	0.350	-	0.350	0.350	trace	0.350	-	-	-
TOTAL (1-TRAIN), M LB/HR	41.667	25.443	92.515	1.752	16.032	110.506	17.119	31.794	47.516	17.187	15.435	1.752	1.475	0.063	50.000
" (2-TRAINS) "	83.333	50.886	185.026	3.504	32.064	220.612	34.238	63.588	95.032	34.374	30.870	3.504	2.950	0.127	100.000
" TPD	1000.0	610.6	2220.3	42.0	384.8	2647.5	410.9	763.1	1140.4	412.5	370.4	42.0	35.4	1.5	1200.0

DESCRIPTION / COMPONENT	16 SCRUBBED FLASH GAS TO COMBUST	17 FLUE GAS TO REACT FURNACE	18 HOT GAS TO DRY/GRIND	19 REACTOR FLUE GAS TO W.H.B.	20 DRYER VENT GAS TO ATMOSPHERE	21 DRYER GAS TO DILUTION	22 RAW WOOD TO SHAFT FURNACE	23 OXYGEN TO SHAFT FURNACE	24 RAW SYNGAS TO SCRUBBERS	25 SYNGAS SCRUBBER SPRAY WATER	26 SYNGAS TO CO_2 ABSORBER	27 ACID GAS VENT TO ATMOSPHERE	28 SYNGAS SLAG FILTER CAKE	29 DRY CATALYST MAKE UP	30 OILY BD TO DIGESTER
PRESSURE, PSIA	14.7	14.8	14.7	14.7	14.7	14.7	14.5	65	14.7	45	200	14.5	14.5	14.5	14.5
TEMPERATURE, °F	100	1500	900	1200	300	300	60	80	200	80	198.4	140	100	60	80
H_2, M LB/HR	0.826	-	-	-	-	-	-	-	0.827	-	0.827	0.001	-	-	-
H_2O, "	1.181	16.702	18.032	8.426	16.344	8.141	16.217	-	21.474	100.000	0.674	1.366	0.600	-	46.930
N_2, "	-	93.863	65.066	47.357	31.036	15.470	-	-	-	-	-	-	-	-	
CO, "	4.292	-	-	-	-	-	-	-	15.067	-	15.067	0.012	-	-	
O_2, "	-	17.579	12.185	8.869	5.012	2.897	-	14.424	-	-	-	-	-	-	
CO_2, "	17.036	28.474	19.740	14.366	9.413	4.693	-	-	14.655	-	14.655	14.530	-	-	
OIL, "	trace	-	-	-	-	-	-	-	0.719	-	-	-	-	-	2.789
SOLVENT, "	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.040
WOOD ($C_6H_9O_4$), "	-	-	-	-	-	-	19.603	-	-	-	-	-	-	-	-
INERTS (N_2+ASH), "	-	-	-	-	-	-	0.257	-	0.009	-	-	-	0.600	-	0.009
Na_2CO_3, "	-	-	-	-	-	-	-	-	-	-	-	-		0.074	0.074
TOTAL (1-TRAIN), M LB/HR	23.335	156.618	115.023	79.018	62.605	31.201	36.077	14.424	52.751	100.000	31.223	15.909	1.200	0.074	
" (2-TRAINS) "	46.670	313.236	230.046	158.036	125.210	62.402	72.155	28.848	105.503	200.000	62.446	31.818	2.400	0.149	
" TPD	560.0	3758.8	2760.1	1896.4	1502.5	748.8	865.9	346.2	1266.0	2400.0	749.4	381.8	28.8	1.8	

Figure 32. Wood to oil plant material balance.

TABLE 78. DESIGN FEEDSTOCK COMPOSITION*

Composition	Moisture Free	As Received
Hydrogen, % wt	6.2	3.41
Carbon, % wt	51.8	28.49
Sulfur, % wt	Trace	Trace
Nitrogen, % wt	0.1	0.055
Oxygen, % wt	40.7	22.385
Ash, % wt	1.2	0.66
Moisture, % wt	-	45.00
	100.0	100.00
HHV, Btu/lb	9,050	4,977
Green Density, lb/cu ft		42
Bulk Density (Chips), lb/cu ft		20

*Assumed 80% pine, 20% spruce bark.

TABLE 79. PLANT DESIGN BASIS AND ASSUMPTIONS

Plant Capacity	Nominal 2000 tons per day based on forest residue availability at a hypothetical site in New England
Plant Stream Factor	90% or 330 operating days per year
Plant Operating Life	20 years
Plant Ownership	Private company
Product Utilization	Supplemental fuel oil for local utilities
Wood Chips Receiving	Nominal 6-days-a-week truck and rail shipment - 2000 cu ft end dump trailers, 4000 to 7000 cu ft chip hopper cars; truck/rail mix about 40:60 on tonnage basis
Wood Chip Storage Pile	Nominal 60-day feedstock supply capacity - 120,000 tons at 20 lb per cu ft bulk density
Wood Chip Reclaim Capacity	200 tons per hour or 240% of design feed rate
Wood Chip Conversion	2-parallel trains at 500 tons per day design rate, 600 tons per day maximum
Wood Chip Drying/Grinding	Dried to 10% moisture with 900°F (inlet) hot gas and ground to minus 50 mesh (90%+)
Wood-to-Oil Reaction Stoichiometry (Assumed)	Basis 0.5 lb CO consumed/lb wood converted -- $\overset{\text{"wood"}}{C_6H_{8.57}O_{3.544}} + \overset{\text{carbon monoxide}}{2.453\ CO} \xrightarrow[650^\circ F \quad 2500\ \text{psia}]{Na_2CO_3} \overset{\text{"oil"}}{C_6H_{8.57}O_{1.091}} + \overset{\text{carbon dioxide}}{2.453\ CO_2}$
Reactor Conversion	80% conversion per pass, 95% overall conversion at 4:1 recycle (370.4 tons per day total conversion)
Reactor	Helical coil in an indirectly-fired heater followed by vertical soaking vessel, 30 min. residence time
Reactor Product Gas/ Liquid Separation	Two-stage flash system
Reactor Heating	Hot gas from combustion of flash gas

(Continued)

TABLE 79. (Continued)

Product/Wood Separation	2:1 solvent to oil dilution, vacuum filtration at 0.1 gpm/sq ft of filter area
Solvent Recovery	Vacuum distillation, thermosiphon reboiler (steam)
Solvent Losses (Assumed)	0.2% of solvent circulation (1.5 tons per day)
Catalyst Removal	Water extraction from product oil
Product Oil Properties (Assumed)	15,000 Btu/lb HHV, 10 lb/gal bulk density, nitrogen-trace, sulfur-trace, ash- 0.5% wt, carbon-73.05%, hydrogen 8.75%, oxygen-17.7%
Product Oil Storage	100,000 gal of heated tankage (30 hours capacity)
Syngas Production	Two parallel trains with 4 PUROX^R converters (2 spares), 433 tons per day wood feed to each train
Wood-to-Carbon Monoxide Reaction Stoichiometry (Assumed)	$11.33\ C_6H_{8.57}O_{3.544} + 35.195O_2 \xrightarrow{3000^oF}$ $42CO + 26CO_2 + 32H_2 + 16.55H_2O$
Oxygen Requirements	0.7234 lb O_2/lb wood converted, 346 tons per day O_2 supplied by a high purity oxygen plant (cryogenic air separation)
Syngas Cleanup	3 stages of water scrubbing
Acid Gas Removal	Benfield hot carbonate process, 1281 moles/hr (dry) design feed rate to each train, 3000 ppmv CO_2 slippage, capacity is 120% of design rate
Catalyst Recovery (Assumed)	Water extraction from syngas converter slag; makeup - 4.4% of catalyst feed (1.8 tons/day)
Process Wastewater Treatment	Anerobic digestion followed by activated sludge
Process Steam	Onsite generation
Electric Power	Purchased
Solid Waste Disposal	Onsite landfill

bottom-mounted vibrating feeders. Each bin compartment and feeder serves an inclined belt conveyor that supplies chips to a processing unit. Conveyor capacities are 150 percent of design flow.

Wood Preparation

Five hundred tons per day of raw wood chips are processed in each wood preparation train. Wood preparation consists of drying (to 10 percent moisture) and grinding (to minus 50 mesh), then blending the ground wood with recycle oil from the reaction section to provide a wood/oil slurry feed to the reactor.

Each train has dryer/grinder units. Wood chips from twin surge bins are fed by screw conveyors into the twin dryer/grinders. Hot gas (900^{o}F) from the reactor heater is introduced to each unit to dry the chips to 10 percent moisture content as they are being ground. The ground wood particles are carried by the gas through the air classifier section, which permits passage of minus 50 mesh material to a cyclone separator (one for two grinders). Plus 50 mesh particles drop back into the grinding section. The cyclone product is discharged through a rotary valve into the wood flour surge bin mounted above the wood/oil blend tank. Cyclone exit gas passes through a baghouse (fabric filter collector) which collects, as product, the fine wood dust escaping the cyclone. Part of the baghouse exhaust gas is recycled to the dryer/grinder inlet hot gas ducts. A portion is released to the atmosphere through the vent on the dryer/grinder building roof. Part is also ducted to the reactor heater as dilution (cooling) gas.

From the surge bin, wood flour is metered continuously (12.7 tons per hour design rate) to a feed hopper on the wood/oil blend tank. Wood flour is slurried to a 30-percent concentration with hot recycle oil in a 20,000-gallon agitated tank. Each wood/oil slurry feed pump supplies about 46 tons per hour (about 170 gpm) of slurry at 400^{o}F and 3500 psi to its respective conversion reactor.

Reactor (Conversion) Section

Each reaction train converts about 305 tons of wood flour into 880 barrels per day (185 tons per day) of oil. Conversion is about 80 percent per pass and 95 percent overall. Catalyst solution, 20 percent sodium carbonate in water, and compressed CO/H_2 reducing gas are injected into the slurry upstream of the reactor. The resultant gas/liquid/solid mixture is charged to the two-part reactor system.

The first part of the reactor consists of a single helical coil (about 2200 feet of three-inch diameter, schedule 160 pipe) mounted vertically in a cylindrical brick-lined furnace (12 feet in diameter by 50 feet high). The second part is a four-foot diameter by 50-foot high vertical pressure vessel. The reactor feed mixture is heated to 650 F and 2500 psia, which provides about 20 minutes hold-up time for additional conversion.

Gas/liquid separation takes place in a two-stage flash system at liquid end conditions of 515^{o}F and about 50 psia. Flash gases (mainly CO_2, unreacted CO, water vapor, and light hydrocarbons) pass through a surge (knockout) drum and into a three-stage water scrubbing system. The scrubbing system cools the gas (to 100°F), condensing water, and hydrocarbons, and removes particulate matter. Hot flash gas enters a spray tower where the gases are water-quenched before entering a venturi for further particulate scrubbing. The entrained water droplets are coalesced and separated in a nonreversing cyclone having a flooded mesh demister section. A surge drum is provided to dampen pressure fluctuations in the cleaned flash gas stream.

Any condensed hydrocarbons are recovered from the scrubbing water in an oil/water phase separation vessel. Hydrocarbons are pumped to product recovery and most of the water is recycled. Water condensed from the gas stream yields a net water input; so a continuous purge is required (to waste treatment).

Scrubbed flash gas (about 168 Btu/SCF) is burned with excess air in a combustion box to provide the hot gases for heating the reactor coil. The combustion products at 1800°F are cooled to about 1500°F by commingling a dryer/grinder vent gas stream prior to entering the reactor furnace. This tempering of the gas limits the coil wall temperature, which helps to minimize fouling of the reactor tube (inside) walls. About half of the furnace tail gas (35,000 SCFM at 1200°F) is used to generate process steam in a waste heat boiler. The remainder is used for drying in the wood preparation section.

The reactor liquid product from the low-pressure flash tank contains unreacted wood, ash, and catalyst. About 80 percent is recycled to the wood/oil blend tank. The remaining 20 percent (205 tons per day from each train) of the raw product oil is pumped to the product separation section.

Product Separation

Two trains of product separation are used to recover a total of 370 tons per day of heavy product oil.

Hot raw oil is pumped to a venturi nozzle inlet to a flash cooling tank. Solvent (xylene) is injected into the venturi section, mixing with the oil and cooling it to about 250°F by vaporization of the solvent. Solvent vapor is condensed in the flash tank overhead system and recovered. The cooled oil stream is further diluted with solvent and pumped to an agitated surge tank. A 2:1 solvent-to-oil ratio is employed to reduce the oil viscosity for the subsequent filtration step.

The diluted oil stream is fed to one of two precoat rotary vacuum drum filters where undissolved wood and inert solids are filtered out. The 10-foot diameter by 16-foot long filters are enclosed and nitrogen blanketed. The filters alternate on a nominal 12-hour cycle. One is in operation while the other is cleaned, precoated with diatomaceous earth, and put in standby position. Filter cake solids are steam-stripped of solvent in a countercurrent steam heated screw conveyor. The dried solids (wood, ash, and filter aid) are collected and transferred to the syngas furnaces for residual energy recovery. The stripped solvent and steam are condensed and phase-separated. Solvent is recycled and the water is sent to wastewater treatment.

The solids-free oil/solvent stream is pumped to a vacuum stripping column (eight-foot diameter x 25 trays) where the solvent is stripped, condensed in

2.0

2.6

the overhead system, and recycled to a solvent surge tank. A thermosiphon reboiler heated with 250 psi, 500°F superheated steam provides stripping vapor. The solvent-free column bottoms stream is water-washed to extract the sodium carbonate catalyst. The oil/water mixture passes through an electrostatic coalescer and into a phase-separation tank. The catalyst-bearing water phase is pumped to the syngas furnace for catalyst processing. Warm product oil (26 gpm) is pumped through steam-traced lines to 25,000-gallon heated storage tanks.

The product tankage provides 30 hours of product storage capacity. Product oil is loaded daily into 5000-gallon heated tank trucks for transport to local utilities which fire the supplemental fuel in steam-generating stations.

Syngas Production

The wood conversion (reduction) reaction requires carbon monoxide as reductant. The PUROX^R process is used to partially oxidize wood, producing a synthesis gas (syngas) containing CO, H_2, CO_2, and water. An acid gas removal step yields the CO-rich gas stream used in the wood conversion reaction. This section is shown in Figure 28.

Two 50-percent capacity syngas production trains convert about 880 tons per day of raw wood to syngas. Each train consists of two syngas shaft furnaces (one spare), a three-stage syngas scrubbing system, a syngas compressor, and an acid gas removal system.

Wood chips from a surge bin are fed into the 12-foot diameter (atmospheric) shaft furnace near the top. High purity oxygen (98 percent minimum) is introduced into the bottom of the furnace where the char material is burned at about 3000°F, producing hot CO and CO_2 that react with the wood in the pyrolysis zone. Drying of the wood feed occurs in the uppper zone of the furnace. Wood (filter cake) recovered in product separation and the catalyst-bearing solution are also injected at the top of the furnace.

A molten slag composed of wood ash and sodium carbonate is discharged from the bottom into a quench tank.

Raw syngas at about 200°F contains some condensible hydrocarbons, tar, and particulate matter which are removed in a dry cyclone separator and a three-stage scrubbing train. Solids collected in the cyclone are normally returned to the furnace, but can also be discharged to an ash bin for disposal. The scrubbing system is similar to that used for reactor flash gas cleanup — a spray tower, venturi, and nonreversing cyclone/demister. Soluble organics in the scrubbing water are purged to the wastewater treatment section. There is a net water production of about 40 gpm resulting from condensation of water vapor in the wet syngas.

Scrubbed syngas (8340 SCFM) is compressed to 200 psig and sent to the CO_2 removal plant (Benfield Proprietary Process). Carbon dioxide is physically absorbed by a hot potassium carbonate solution in a packed absorption column. The carbon dioxide-rich solution is stripped of CO_2 in a packed regeneration column, and the lean solution bottoms is returned to the top section of the absorber. Reboiler steam (75 psig saturated) is supplied by a waste heat boiler recovering energy from 1200°F reactor tail gas. The acid gas (2570 SCFM), mainly CO_2 and water vapor, is vented to the atmosphere. CO-rich product gas (about 6000 SCFM) is compressed to 4000 psig for injection into the wood/oil slurry upstream of the reactor.

One 400-ton-per-day oxygen plant will supply the oxygen requirements for both syngas trains. The two spare syngas furnaces will provide the capability for virtually continuous two-train production. No liquid oxygen storage is provided. Oxygen is produced by conventional air separation involving air liquefaction and fractional distillation into its separate components. The oxygen plant is supplied as a package unit except for the air compressor and oxygen compressor.

Catalyst Recovery

Soluble sodium carbonate is recovered from the syngas slag quench tanks by physical separation (two recovery trains). The slag/water slurry is filtered in a rotary vacuum filter to remove the insoluble materials (mainly wood ash and filter aid). Part of the filtrate stream is purged to the wastewater treatment system to prevent a buildup of soluble inorganics in the catalyst system. The remainder is recycled to a catalyst makeup (and surge) tank. As needed, anhydrous Na_2CO_3 (light soda ash powder) and water are added to the agitated makeup tank to maintain a 20 percent Na_2CO_3 solution. A total of 21 tons per day of solution from each train is injected at 3500 psia into the wood/oil slurry feed to the reactor makeup. The Na_2CO_3 quantities are expected to be small because the wood ash should be a source of (catalyst) alkaline material. (It may be necessary to (pulverize) grind the quench slag in order to improve the dissolution of occluded Na_2CO_3.)

Auxiliary Facilities

The plant's main auxiliary facilities are a utility boiler to provide process and heating steam, a raw water treatment system to supply plant water, a circulating water system to provide cooling water, and a wastewater treatment system to clean up liquid effluent streams.

Utility Boiler

Process and heating steam requirements are supplied by a 50,000 lb/hr capacity (250 psia, 500°F) wood-burning boiler. Normally only about 25,000 lb/hr of steam are required. The higher capacity was selected to meet peak demands of wintertime operation, 120 percent plant throughput, and the failure of one waste heat boiler (process steam supply to Benfield plant).

The boiler system consists of a traveling grate stoker with a two-drum vertical boiler unit and an economizer. The boiler is also equipped to fire gaseous fuel. Wood chips from the transfer house are supplied to the boiler silo by an inclined belt conveyor. A mechanical fuel distributor feeds in wood chips above the grate (about four tons per hour). A forced draft fan supplies combustion air to the furnace. Hot combustion products pass through the radiant and convection sections and are ducted to an electrostatic precipitator for fly ash collection (99.5 percent removal efficiency). An induced draft fan boosts the

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flue gas to slightly above atmospheric pressure and the cleaned gas is discharged to the atmosphere through a 100-foot tall steel stack. Fly ash and bottom ash are conveyed to an ash bin and hauled off periodically for disposal. Feedwater supplied to the boiler is composed of about 80 percent recovered condensate and 20 percent makeup (demineralized raw water).

Raw Water Treatment System

Figure 33 presents a summary water balance for the plant. Raw water is supplied to the plant from the nearby river. The maximum demand is about 250 gpm. A small pump house near the bank of the river pumps water through a 3000-foot long, four-inch diameter steel pipe to the onsite raw water storage basin. The earthen (settling and surge) basin has a 900,000-gallon capacity of a 2½-day supply, at the maximum makeup demand. (The basin water pumps can also supply water directly to the cooling tower for makeup.) Basin water is pumped to the plant water treatment system, which consists of a gravity sand filter, a chlorinator, and a filtered water storage tank. Filtered water is pumped into the plant distribution system (utility and potable water). Water for boiler feed makeup (three boilers) and pump system supply makeup is demineralized and pumped to the boiler condensate storage tanks. The total treated plant water demand averages about 80 gpm.

Recirculating Water System

Process auxiliary cooling duties total about 90 million Btu/hr. A recirculating water system supplies 80°F water to all of the exchanger-coolers. A three-cell induced-draft cooling tower (33 feet wide by 73.5 feet long) dissipates the heat load to the atmosphere by evaporation and sensible heat transfer. Each cell is equipped with a 168-inch diameter fan. Summer design conditions are a 70°F wet bulb, a 10°F approach, and a 30°F cooling range. Two 50-percent capacity pumps pump about 6000 gpm of cooled water from the tower basin to the circulating water distribution system. The tower is operated at a nominal 25 cycles of concentration with river water as the makeup source (treated wastewater is an alternate source). Evaporation and drift losses average about 128 gpm. The cooling water is shock-chlorinated for 90 minutes each day to control fouling organisms. Sulfuric acid is added to the makeup water as a scale ($CaCO_3$) control measure.

Basin heaters (immersion steam coils) are used to prevent freezing during shutdown of one or more cells in cold weather.

Wastewater Treatment System

Principal wastewater streams in the plant are:

- Boiler blowdown and regenerant brines
- Cooling tower blowdown
- Utility wastewater (yard and building drains)
- Sanitary wastewater

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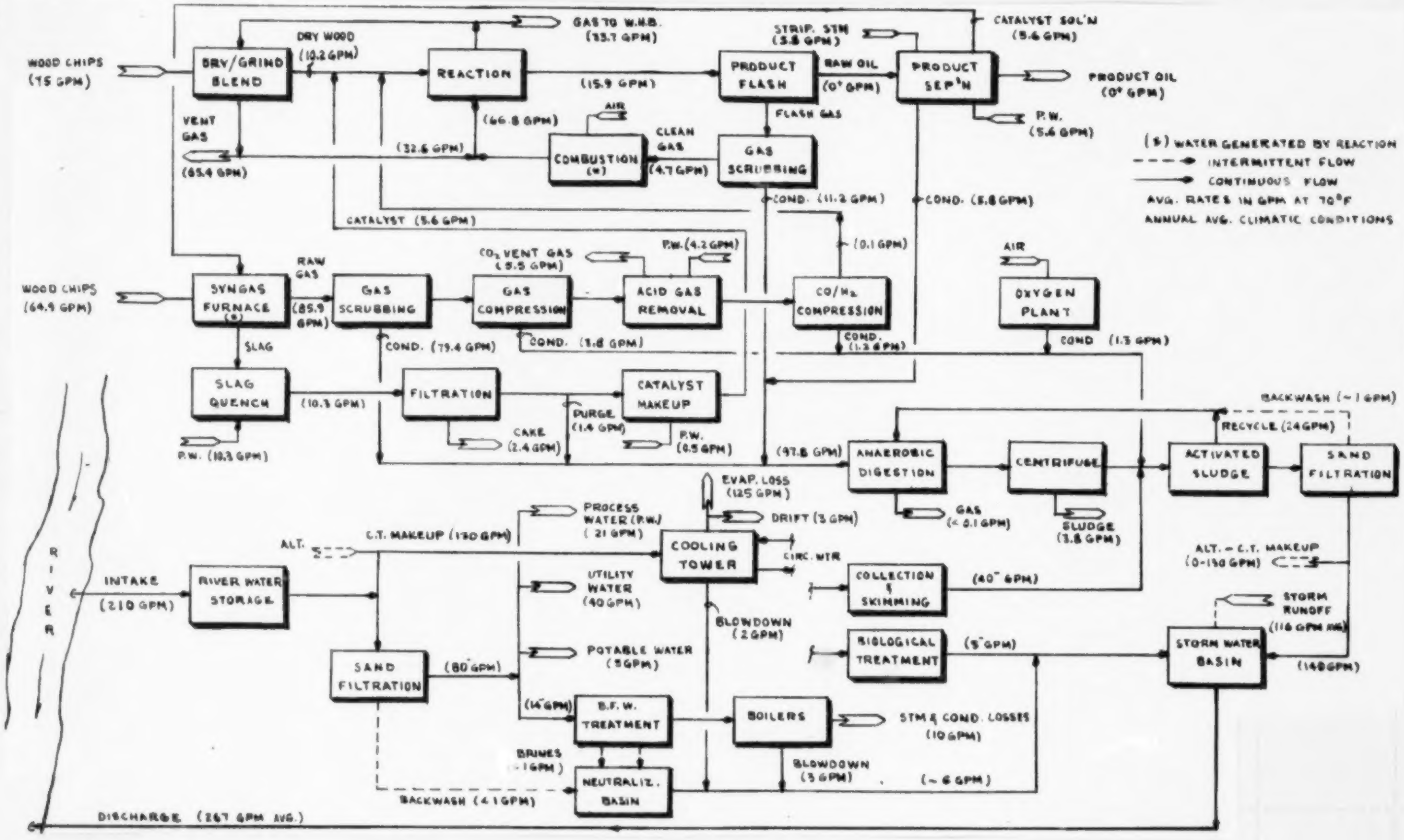
WOOD CHIPS (75 GPM)
DRY/GRIND BLEND
DRY WOOD (10.2 GPM)
REACTION
GAS TO W.H.B. (33.7 GPM)
(15.9 GPM)
PRODUCT FLASH
STRIP. STM (3.8 GPM)
RAW OIL (0* GPM)
PRODUCT SEP'N
CATALYST SOL'N (5.6 GPM)
PRODUCT OIL (0* GPM)
P.W. (5.6 GPM)
VENT GAS (65.4 GPM)
(32.6 GPM)
(66.8 GPM)
AIR
COMBUSTION (*)
CLEAN GAS (4.7 GPM)
GAS SCRUBBING
FLASH GAS
COND. (11.2 GPM)
COND. (5.8 GPM)
CATALYST (5.6 GPM)
(0.1 GPM)
(*) WATER GENERATED BY REACTION
INTERMITTENT FLOW
CONTINUOUS FLOW
AVG. RATES IN GPM AT 70°F
ANNUAL AVG. CLIMATIC CONDITIONS
WOOD CHIPS (64.9 GPM)
SYNGAS FURNACE (*)
RAW GAS (85.9 GPM)
GAS SCRUBBING
CO_2 VENT GAS (5.5 GPM)
GAS COMPRESSION
P.W. (4.2 GPM)
ACID GAS REMOVAL
CO/H_2 COMPRESSION
AIR
OXYGEN PLANT
COND. (79.4 GPM)
COND. (1.8 GPM)
COND. (1.3 GPM)
COND (1.3 GPM)
SLAG
SLAG QUENCH
(10.3 GPM)
FILTRATION
CATALYST MAKEUP
P.W. (10.3 GPM)
CAKE (2.4 GPM)
PURGE (1.4 GPM)
P.W. (0.5 GPM)
(97.8 GPM)
ANAEROBIC DIGESTION
CENTRIFUGE
ACTIVATED SLUDGE
SAND FILTRATION
BACKWASH (~1 GPM)
RECYCLE (24 GPM)
GAS (< 0.1 GPM)
SLUDGE (3.8 GPM)
EVAP. LOSS (125 GPM)
DRIFT (3 GPM)
PROCESS WATER (P.W.) (21 GPM)
ALT.
C.T. MAKEUP (130 GPM)
COOLING TOWER
CIRC. WTR
COLLECTION & SKIMMING
(40* GPM)
ALT. - C.T. MAKEUP (0-130 GPM)
R I V E R
INTAKE (210 GPM)
RIVER WATER STORAGE
UTILITY WATER (40 GPM)
BLOWDOWN (2 GPM)
STORM RUNOFF (116 GPM AVG)
POTABLE WATER (5 GPM)
BIOLOGICAL TREATMENT
(5* GPM)
STORM WATER BASIN
(140 GPM)
SAND FILTRATION
(80 GPM)
(14 GPM)
B.F.W. TREATMENT
BOILERS
STM & COND. LOSSES (10 GPM)
BRINES (~1 GPM)
NEUTRALIZ. BASIN
BLOWDOWN (3 GPM)
(~6 GPM)
BACKWASH (4.1 GPM)
DISCHARGE (267 GPM AVG.)

Figure 33. Wood to oil plant, simplified water balance.

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- Compressor condensates
- Catalyst solution purge
- Oily condensates from gas cleaning
- Storm water drainage (intermittent)

The blowdown (high total dissolved solids) streams are collected in a small neutralization basin for blending, settling, and pH adjustment, if necessary, and then sent to the stormwater holding basin before discharge to the river. Utility wastewater and condensates from compressor coolers are collected in process area sumps with oil skimming facilities before being sent to the biological treatment system. Sanitary wastewater is collected and treated in a packaged biological treatment unit. The effluent is disinfected with chlorine and sent to the stormwater basin.

The 3.9-million-gallon capacity earthen basin is able to impound about 50 percent of the runoff from 75 acres during a 10-year, 24-hour storm. That is, the basin provides about 12 hours of runoff holding capacity for this 10-year event and total impoundment capacity for runoff from most rainfall events. The basin also can serve as a final settling pond for the normal plant effluents.

Oily condensates, particularly from syngas scrubbing, are expected to contain substantial concentrations of dissolved organics. These condensates are treated in an 800,000-gallon capacity anaerobic digestion tank which converts part of the dissolved and undissolved organics into methane and carbon dioxide. Raw digester gas is compressed and recirculated through submerged hydraulic mixer units to mix the digester contents. Compressed raw gas product (about 570 Btu/SCF) is burned with wood in the utility boiler to generate process steam.

Digester effluent is sent to a solid-bowl centrifuge which concentrates the digester solids to a 15 to 20 percent weight centrifuge cake. The cake is transported to the utility boiler and burned with the wood chip fuel. The fuel value of the digester gas is expected to more than offset the low heating value (high moisture content) of the sludge cake — resulting in a net energy contribution from the digestion system.

Mother liquor from the centrifuge is sent to an activated sludge system for a second stage of biological treatment. Utility wastewater and compressor condensates (ca 50 gpm) are also aerobically treated in the 250,000-gallon aeration basin. Basin mixed liquor is clarified in a conventional gravity clarifier and the settled sludge is recycled to the aeration basin. A portion of the recycle sludge stream is pumped to the digester to maintain the desired mixed liquor solids concentration in the aeration basin. This sludge, generated by the biological process, is ultimately burned in the boiler.

Overflow from the clarifier is filtered in a gravity sand filter to remove residual suspended solids. Filtered effluent is sent to the stormwater basin for discharge to the river. Alternatively, most of this wastewater could be

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pumped to the cooling tower as part or all of the makeup requirement for the recirculating water system (RCWS). A high residual organic content or a high dissolved solids content could limit the effective cycles of concentration attainable in the RCWS.

The total plant liquid discharge (dry weather flow) could be less than 25 gpm if process effluent were used to supply the total cooling tower makeup demand.

Solid Waste Disposal

Plant solid wastes consist mainly of mineral residue (ash) from the syngas and utility boiler units. This material, plus plant trash and garbage, is buried onsite in a conventional landfill (spread, compact, and cover). About 11 acre-feet of solid waste is generated per year. A three-acre site will be developed initially for solid waste disposal. Additional area will be developed as the initial site is filled.

Relief and Blowdown System

All pressurized systems handling hydrocarbons or other combustible materials are equipped with safety and relief devices venting to the blowdown system. Certain equipment normally has continuous vents to purge noncondensible gases (which may also contain combustible gas). The blowdown and flare system is designed to collect and incinerate normal process vent gases as well as handle the largest credible release in an emergency (venting of one train — syngas, reactor product, oil/solvent separation). The blowdown system is connected to a knockout drum and a 16-inch diameter by 94-foot high elevated flare located away from the process area.

Plant Energy Balance

An overall plant energy balance can be calculated in a "simple" way — the total value of direct energy inputs (feedstock and electric power) minus the energy value of the product oil equals the energy "lost" or dissipated to the surroundings. The balance on such a basis is summarized in Table 80.

However, these energy values are not really equivalent, since they are not all fuel heating values. If electric power consumption is converted to a fuel basis on a 22-percent conversion efficiency (see wood-to-power), then the conversion efficiency becomes 100 x 463.05 ÷ 1098.4 = 42.1 percent.

TABLE 80. THERMAL BALANCE ELEMENTS — WOOD TO OIL

Form	Quantity		MM Btu/hr
Total Feedstock Input	83,333 lb/hr to reactors		
	72,155 lb/hr to syngas production		
	8,225 lb/hr to utility boiler		
	163,713 lb/hr at 4,977 Btu/lb	=	814.8
Electrical Power Input	24,500 hp at 2,545.1 Btu/hr/hp	=	62.4
TOTAL			877.2
Product Oil Output	30,870 lb/hr at 15,000 Btu/lb	=	463.05
Heat Rejection			414.15
Direct Conversion Efficiency	463.05/877.2 (100) = 52.8%*		

* Efficiency drops to 42.1% if the fuel equivalent of electric power is included at 22 percent conversion efficiency (15,514 Btu/kWh).

WOOD-TO-OIL PLANT COSTS

A conceptual estimate was made for the wood-to-oil plant on the hypothetical 110-acre site in New England. Table 81 summarizes major capital costs. Details are presented in Appendix C. Mechanical equipment and piping are the largest field cost items reflecting the materials handling and chemical processing nature of the conversion plant. Pollution control equipment costs are a little more than three percent of the direct field cost. Aqueous waste treatment systems account for most of the pollution control costs. The $99.1 million total investment for the 1764-barrel-per-day production ($56,000/BPD) is not directly comparable to the conventional petroleum production and refining costs since the "oil fossil fuel" is not really "produced" in the same sense. For a biomass comparison, SRI (11) reports an estimated investment of about $144 million for a 5268 BPD wood liquefaction plant, or about one-half the investment on a $/BPD basis.

Annual operating costs in Table 82 exclude the wood feedstock cost. The utilities cost, which is nearly all electric power at 3¢/kWh, is the largest single operating expense, exceeding the combined costs of operating labor, supervision, and maintenance labor and materials. In some situations, it may be advantageous to produce power on site from wood. As indicated in Section 3, the cost of electricity generation from wood would be on the order of 3¢/kWh,

TABLE 81. WOOD-TO-OIL CAPITAL COSTS

Element	$1,000,000's
Site and Yard	1.6
Civil/Structural	4.8
Process Mechanical Equipment	27.6
Pollution Control Equipment	1.7
Piping and Instrumentation	10.5
Electrical	4.6
DIRECT FIELD COST	50.8
Indirect Field Cost	6.5
TOTAL FIELD COST	57.3
Engineering Services	6.9
	64.2
Allowance for Uncertainty	12.8
TOTAL CONSTRUCTION COST	77.0
Land	0.4
Other Owner Costs	1.5
Startup	7.7
Allowance for Funds During Construction	7.8
FIXED CAPITAL INVESTMENT	94.4
Working Capital	4.7
TOTAL CAPITAL COST First Quarter 1978, Price and Wage Levels	99.1

excluding wood costs. Economically there would be no advantage unless wood were essentially free or the cost of supplying power to the plant were considerably higher than 3¢/kWh.

Table 83 presents simplified annualized costs of oil production. On this simplified basis, annual capital and annual operating costs are nearly equal, each representing about $3/MM Btu of fuel heat value.

Figure 34 illustrates the impact of wood cost on the cost of fuel oil for utility and private financing. At zero wood cost, the oil production cost is about $39/bbl, or $6.22/MM Btu of fuel heat value, for a utility owner and $52/bbl for a private owner. Each dollar per (wet) ton of wood cost adds about $1.11 (utility) and $2.12 (private) to the cost per barrel.

On a Btu basis, wood at $1/MM Btu gives a (utility) oil cost of about $8/MM Btu, or more than three times current prices for fuel oil (say, $2.50/MM Btu). Two factors in part contribute to the high cost: (1) the conversion process, as conceptualized here, is not very energy-efficient, and (2) the low plant capacity (for a justifiable reason) militates against some economies of scale. SRI's comparable values for utility financing indicate an oil cost of $5.37/MM Btu, or $3.12/bbl, for a plant with three times the production capacity (11).

WOOD-TO-OIL ENVIRONMENTAL ASSESSMENT

Feedstock Procurement Impacts

Collection and transport of some 650,000 tons per year of residue will have environmental impacts on land, water, air, and biological resources in the area. Removal of forest residues may have profound environmental impacts, both beneficial and harmful. General impacts, addressed in the following sections, will be similar to those described in Section 3, but modified by the forest type and its different plant species.

Forest Protection--

Large amounts of residues are generated in the growth and logging of forest stands (40). Poor quality trees, understory vegetation, death of trees caused by natural events, diseases and attack of insect pests, and thinning often generate considerable tonnage of residues which may be a serious hazard, especially during dry periods of the year. The accumulation and removal of these residues will be an important forest fire prevention measure.

Prevention of Disease and Insect Pests--

Organic residues attract a number of insect pests. Some insects spend a part of their life cycle in the residue. For instance, epidemics of bark beetles have started in residues (41) and other insects associated with forest residues are known to have damaged spruce (bud worm), hemlock, cedar, and other species of forest trees. Moreover, insect pests become vectors of harmful plant diseases, Removal of residues will help to alleviate problems caused by insect pests.

TABLE 82. ANNUAL OPERATING AND MAINTENANCE COSTS* – WOOD TO OIL

Element	$1,000,000's
Supplies	0.6
Utilities	4.3
Operating Personnel	2.0
Maintenance Labor and Materials	1.1
Supervision	0.4
Administration and Overhead	0.7
Local Taxes and Insurance	2.0
TOTAL ESTIMATED ANNUAL OPERATING COST First Quarter 1978, Price and Wage Levels	11.1

*Excluding wood feedstock.

TABLE 83. ANNUALIZED COST OF OIL PRODUCTION

Element	$1,000's	$/Bbl	$/MM Btu
Annualized Capital Cost (9%)	10,764	18.30	2.91
Annual Operating Cost	11,100	18.88	3.00
Annual Wood Cost (Base: $10/ton)	6,550	11.14	1.76
TOTAL ANNUALIZED COST	28,414	48.32	7.67

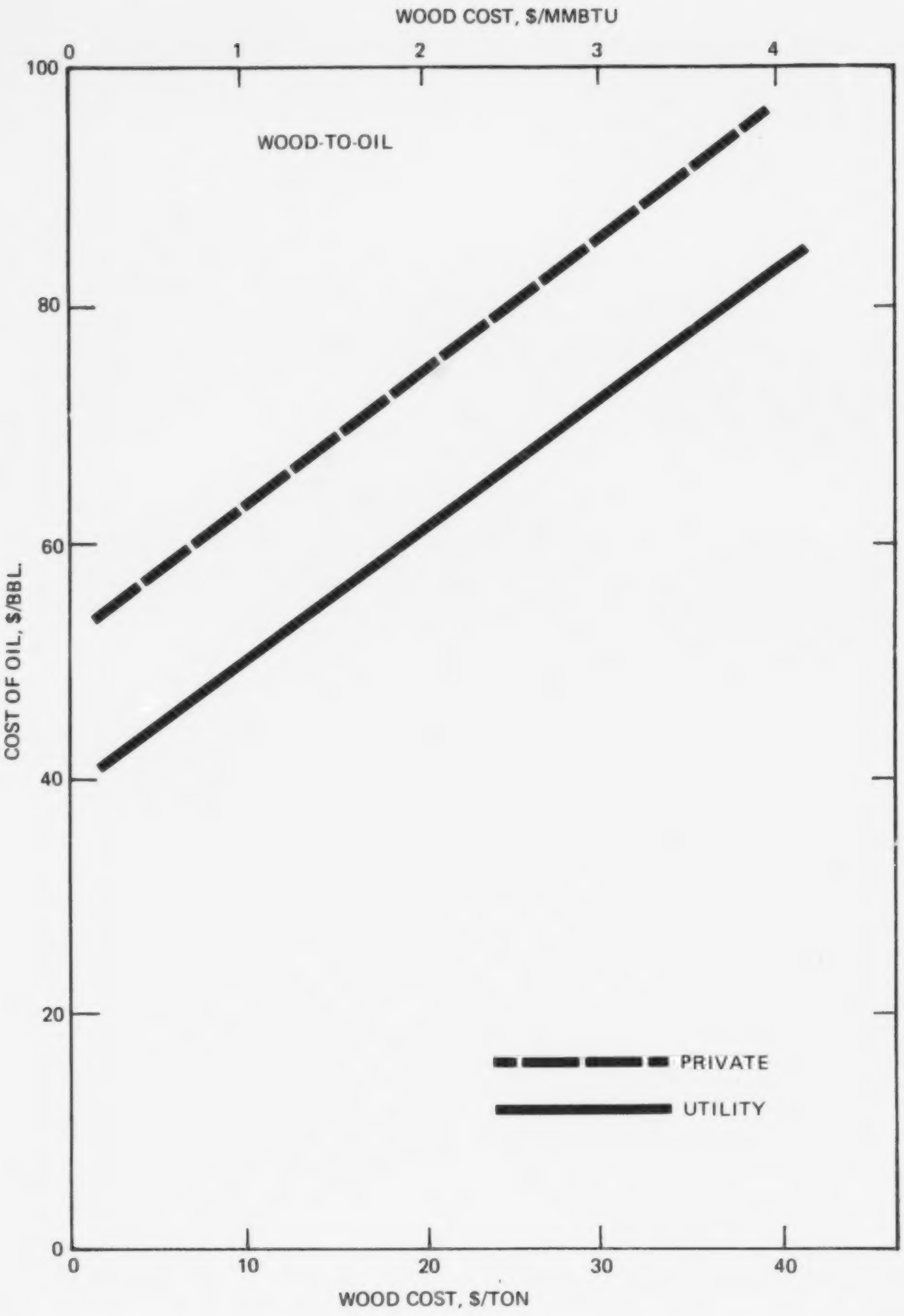

Figure 34. Effect of wood cost on cost of oil with both private and utility financing.

Forest Regeneration and Stand Development--

Large quantities of forest residues can impede the germination of seeds and the development of seedlings. Optimum amounts of residues, however, may form desirable seedbeds for new growth. Moist, decayed organic matter may be the ideal environment for regeneration of the forest.

By affording nutrient supply, large residues (stumps, etc.) may protect new saplings. Residues, however, may prevent germination of such species as red alder and firs, which require mineral soils for seedling establishment. On balance, removal of at least a portion of the residues would probably constitute positive, rather than negative environmental impacts.

Maintenance of Soil Fertility and Erosion Control--

Excessive removal of forest residues will cause depletion of the nutrient elements. Leaves are especially rich in nutrients and their complete removal will obviously cause deficiencies in such elements as nitrogen, potassium, phosphorus, and sulfur, depending on nutritive makeup of the soil (41). Mineral deficiencies of this nature will have to be corrected by the incorporation of fertilizers — an expensive alternative.

Excessive residue removal in the area will also result in soil erosion, especially on slopes. In addition to soil loss, secondary impacts such as sedimentation and bank cutting of streams and loss of water quality could occur in some areas.

Water Quality--

The presence in streams of fine residues caused by soil erosion can increase biological oxygen demand and thus influence stream biology by reducing the amount of dissolved oxygen for fish. Sedimentation can also impede fish migration, eliminate spawning beds, and destroy rooted aquatic vegetation.

Wildlife Habitat--

Inasmuch as forest residues generally provide habitats and cover for a variety of biota, excessive removal may be detrimental for some species of small mammals and birds. Wildlife will be disturbed by the collection activities and will temporarily move to new habitats in the near-by forest. This displacement could result in increased mortality for strongly territorial species, especially during breeding or nesting seasons.

Recreation and Aesthetics--

Optimum levels of removal of heavy logging residues will improve recreational and aesthetic prospects in most situations.

Transportation--

Wood chip shipments to the conversion plant will average (annual operating basis) 100 truck loads or 40 (5000 CF) rail hopper car loads per day. Other mobile equipment will be involved in collection of residue on forest lands by off-road activities. The additional transportation burden on local roads, state highways, and rail lines will be small (probably less than one percent) compared with the current annual vehicle-mileage or ton-mileage in the collection area (about 6000 square miles). Some local congestion could be expected at times in the vicinity of the plant because of chip haul traffic.

Motor fuel consumption for residue collection will be on the order of 1.5 percent of the conversion plant's fuel production. Vehicle pollutant emissions will increase as a result of this fuel consumption, a small though adverse effect on ambient air quality.

Socioeconomic--

Local income and employment will increase as a result of residue procurement activities, a benefit to the economy of the area. Some 30 to 50 new permanent jobs will be created, as well as some part-time employment opportunities for loggers. Several million dollars will be paid annually for wood delivered to the plant. Manpower and community service resources in the area will not be unduly strained by the demands of this new activity.

Summary--

Table 84 summarizes principal impacts anticipated in forest residue collection. As in the wood-to-power scenario, a considerable amount of land area will be affected by forest residue collection. Environmental impacts will have both positive and negative aspects. With proper management of collection activities, forestland productivity and appearance could be improved, with economic and perhaps recreational benefits for the community. However, some damage to soil stability and wildlife habitats should be expected. Severe damage to forestlands could occur through excessive removal of residues and careless harvesting practices, resulting in soil erosion and degradation of surface waters.

TABLE 84. PROCUREMENT IMPACT SUMMARY – FOREST RESIDUE

Environmental Factors	Residue Procurement Impacts	Potential Mitigating Measures
Air Quality	Minor adverse impact from vehicle pollutant emissions and localized fugitive dust emissions	
Surface Water	Potential degradation of stream qualities resulting from soil erosion – secondary effects such as increased turbidity and organic loading	Avoid or limit residue collection on unstable soils
Groundwater Quality	No direct impact	
Land	Abundant forestland in region-yarding areas only direct land requirement; agreements with land owners needed to collect enough residue for 20 year plant life	Develop residue collection and management to ensure supply
Ecology and Critical Habitat	About 20,000 to 70,000 acres subjected to residue collection annually; judicious collection can improve forest productivity, reduce fire, disease and insect damage; some damage to vegetation expected during collection, disturbance of wildlife habitats and possible permanent displacement of and loss by increased mortality to some animal species	Wildlife surveys needed to avoid critical habitats; management of collection activities to minimize damage of vegetation and wildlife
Soils and Geology	Nutrients in residue removed may result in degradation of soil fertility; complete removal may cause serious mineral deficiencies; potential increase in soil erosion on unstable terrain	Soil surveys and monitoring of collection activities to prevent damage to soil fertility and stability; import fertilizers, if necessary to replenish nutrients

(Continued)

TABLE 84. (Continued)

Environmental Factors	Residue Procurement Impacts	Potential Mitigating Measures
Aesthetic and Recreational Resources	Some improvement in appearance of logged areas; potential increase in recreational value of forest land	Avoid excessive removal that leads to erosion and degrades aesthetic qualities
Community Economy	$6.5 million annual input to local economy through purchase of delivered residue-significant benefit	
Community Population and Services	Little increase expected in local population and in demands for services	
Labor Availability	Local labor supply is adequate to fill the jobs created by residue procurement — benefit to local work force.	
Transportation	Small increase in rail and road traffic in region; local congestion may occur on principal residue haul routes	

Plant Impacts

Construction and operation of the wood-to-oil plant would have impacts on the environment in the vicinity of the hypothetical plant site. These impacts are broken down into physical/chemical, biological, aesthetic, and socioeconomic categories for discussion.

Estimates of physical resources committed to operation of the plant over its 20-year life are summarized in Table 85. Table 86 presents annual chemical requirements.

Construction of the plant will also involve the utilization of additional resources — manpower, fuel, water, and all the construction materials. The total construction period is assumed to be three years. During the peak of construction, several hundred workers will be on site.

Physical/Chemical Impacts--

Physical/chemical emissions from the plant are categorized as air, water, and solid waste emissions. Direct impacts from these emissions on air, water, land, and biota are discussed below.

TABLE 85. RESOURCES COMMITTED TO PLANT OPERATION

Resource Category	Quantity	Normalized Quantity (Output)*
Land	110 acres	0.24 acres/MM Btu/hr (62.4 acres/MBPD)
Feedstock	655,000 tons/yr	353.7 lb/MM Btu
Auxiliary Fuel	13,300 MM Btu/yr	3,590 Btu/MM Btu
Chemicals	2,130 tons/yr	1.15 lb/MM Btu
Electric Power	146 MM kWh/yr	39.5 kW/MM Btu/hr
Water	100.8 MM gal/yr	27.2 gal/MM Btu
Manpower (145 employees)	290,000 manhours/yr	0.078 manhours/MM Btu

*Basis: 3.704 trillion Btu/yr net output.

Air Emissions--The wood-to-oil conversion plant will be equipped with pollution controls to limit pollutant emissions to the atmosphere. Significant emission sources and estimated emission rates are listed in Table 87. Particulate emissions from wood chip transfer operations are controlled where practical by the enclosure of transfer points and the use of fabric filter collectors on exhaust air streams. Uncontrolled emission sources are the dump hopper, the pneumatic conveyor discharge paper, and the chip storage pile. A large fraction of the particulate matter entrained in the air streams will probably settle out quickly and close to the emission source. Suspended particulate matter emissions are expected to be low, even from uncontrolled sources.

The dryer/grinder units will produce large amounts of fine wood dust. Baghouses will be used to clean the exhaust gas before it is vented (part of it) to the atmosphere. The dryer/grinders are expected to be the largest particulate matter sources in the plant. Uncontrolled emissions could be several tons per day.

Vent gases from the dryer/grinders and from the waste heat boilers originate from combustion of reactor flash gas. As such, the combustion product gases will contain small amounts of nitrogen oxides, carbon monoxides, and unburned hydrocarbon pollutants that will be emitted to the atmosphere. The utility boiler will be the other source of combustion product pollutants. The boiler will have an electrostatic precipitator for particulate matter removal as its only pollution control device. None of the combustion sources will emit

TABLE 86. SUMMARY OF ANNUAL CHEMICAL REQUIREMENTS – WOOD TO OIL

Chemical	Amount Per Year
Solvent (o-xylene)	1 MM lb
Diatomaceous Earth	950 tons
Soda Ash	590 tons
Lime	40 tons
Chlorine	16 tons
Caustic Soda (50%)	10 tons
Sulfuric Acid (66° Be)	13 tons
Polymer	2 tons
Misc. Water Treatment Chemicals	1 ton
Benfield Solution	2,000 gal
Ion Exchange Resins	5 cu ft
Lube Oil	3,300 gal
Auxiliary Fuel	
Diesel	66,000 gal
Gasoline	15,000 gal
Natural Gas	2,400 MSCF

TABLE 87. SUMMARY OF ESTIMATED AIR EMISSIONS — WOOD TO OIL

Source	Flow Quantity	Pollutants	Emission Rate
Chip Dump Hopper	2330 tons/14-hr day, 6 days/week	Fugitive dust-suspended particulates	23 lb/day
Chip Transfer Bins	2330 tons/14-hr day, 6 days/week(1200 CFM)*	Fugitive dust (.1 gr/CF)	14 lb/day
Pneumatic Chip Conveyors	2330 tons/14-hr day, 6 days/week(5600 CFM)	Fugitive dust	23 lb/day
Chip Storage Pile	120,000 tons stored 9-10 acres of land	Fugitive dust	50 lb/day
Transfer House Vent	2000 tons/day chips (600 CFM)*	Fugitive dust (.1gr/CF)	12 lb/day
Dryer/grinder Feed Bins (4)	1000 tons/day (400 CFM)*	Fugitive dust (.1 gr/CF)	8 lb/day
Syngas Feed Bins (4)	865 tons/day (400 CFM)*	Fugitive dust (.1 gr/CF)	8 lb/day
Boiler Feed Silo	100 tons/day (100 CFM)*	Fugitive dust (.1 gr/CF)	2 lb/day
Dryer Baghouse Vents (2)	15,250 CFM exhaust each*	Particulate matter (.02 gr/CF) NO_x(0.5 lb/MM Btu)† CO(0.05 lb/MM Btu)† HC(0.05 lb/MM Btu)†	125 lb/day 25 lb/day 2.5 lb/day 2.5 lb/day
Waste Heat Boiler Stacks (2)	17,500 SCFM each	Particulate matter(.004 gr/CF) NO_x(0.5 lb/MM Btu)† CO(0.05 lb/MM Btu)† HC(0.05 lb/MM Btu)†	30 lb/day 35 lb/day 3.5 3.5
Acid Gas Column Vents (2)	2570 SCFM each	CO H_2	288 lb/day 48 lb/day

(Continued)

TABLE 87. (Continued)

Source	Flow Quantity	Pollutants	Emission Rate
Utility Boiler Stack	13,500 SCFM	Particulate matter	36 lb/day
		NO_x(0.5 lb/MM Btu)†	500 lb/day
		SO_x(<0.01 lb/MM Btu)†	<10 lb/day
		CO(0.1 lb/MM Btu)†	100 lb/day
		HC(0.1 lb/MM Btu)†	100 lb/day
Oxygen Plant Nitrogen Vent	21,600 SCFM of N_2	None	
Cooling Tower Exhaust	354,000 SCFM (dry air)	Drift(water droplets)	36,000 lb/day
		Salts	60 lb/day
		HC**	
Flare	Small	CO, HC, NO_x	Small

*Fabric filter collector on vent stream.
†Assumed emission factors.
**Potential hydrocarbon emission if treated wastewater used as makeup water.

significant amounts of sulfur oxides. The Benfield regeneration columns will release acid gas streams rich in CO_2. Small quantities of carbon monoxide and hydrogen will also be released. The flare system will routinely incinerate small quantities of hydrocarbon vapors vented from process units. Only during emergency conditions would the flare be a significant combustion source.

The air separation plant and the cooling tower will be large emission sources in terms of flow, but their discharges will not be particularly harmful to the air quality. Drift from the cooling tower will deposit water droplets and salts on the ground in the vicinity of the tower. If treated wastewater were used for cooling tower makeup, there would be some dissolved organics in the drift loss and probably some volatile organics in the exhaust air.

Overall, the plant emissions will have a small adverse effect on ambient air quality in the area. The plant could be considered a major new source with respect to particulate matter, since potential emissions exceed 100 tons per year. Air quality in the vicinity of the plant meets primary standards except for photochemical oxidants. Hydrocarbon storage (product oil, solvent, and vehicle fuel) tanks will be equipped with vapor control or vapor collection systems. Total hydrocarbon storage capacity is less than 5000 barrels. Hydrocarbon emissions from the plant will be low and will not contribute significantly to atmospheric pollution. Combustion products from mobile sources (wood hauling) may be the largest contributor to oxidant formation.

Water Emissions--Total plant process wastewater will average about 150 gpm. Table 88 summarizes estimated emissions. Oily condensates from gas scrubbing are expected to contain high concentrations of dissolved organic materials. Compositions of the condensed hydrocarbons cannot be easily predicted, but they are likely to include a variety of alcohols, aldehydes, ketones, and organic acids. The two-step biological treatment (anaerobic digestion and activated sludge) should remove most of the biologically degradable organics. Residual organic material in the treated effluent will be discharged to the river. Most of the process effluent will be used as cooling tower makeup if it is low in TDS and organics. The characteristics of the residual organics are not known. In terms of gross pollutant measures, such as biochemical oxygen demand, chemical oxygen demand, or organic carbon, the mass emission rate of pollutants will not be large. It is possible that some toxic or carcinogenic materials may be generated in the syngas or wood conversion processes and may pass through the wastewater treatment processes. At this time there is no information available to assess whether or not a hazardous materials problem will exist.

Utility wastewater will also be biologically treated and will not be a significant source of organic pollutants. Sanitary wastewater (after separate biological treatment) and blowdowns from the boiler and cooling tower will be low-volume wastewater sources. Dissolved solids emissions in the blowdown streams are the result of concentration of TDS in the river water, plus added chemicals containing inorganic ions. If the cooling tower makeup water were treated wastewater, the cooling tower blowdown would need to be biologically treated for high concentrations of organic materials.

Storm runoff collected from process areas will average over 100 gpm on an annual basis. It will be a large intermittent effluent source. Stormwater will pick up wood particles and perhaps some oily material from process areas. During wet weather periods, part of the runoff could be used as makeup to the cooling tower. After passing through the stormwater settling basin, it will be discharged to the river. After settling, the discharged stormwater will contain the low concentrations of dissolved pollutants that were picked up through contacts with the various surface areas in the plant. During storm periods, stormwater will be the largest source of pollutant emissions in the plant by virtue of its large volumetric flow.

Although it is difficult to predict actual pollutant loads from the conversion plant, the application of available control technology should produce effluents low in pollutant concentrations. The residual pollutants discharged to the river will probably have no measurable effect on river water quality, though the addition of any pollutants would have an adverse, though minor, effect on the river as a water resource. Plant effluents are expected to have no effect on groundwater resources.

Solid Waste Emissions--Solid wastes generated by the processes originate from the noncombustible portion of the wood feedstock and from materials such as filter aid and catalyst added to the process. The nonrecoverable solid wastes will be buried in an onsite landfill. An estimated total of 1200 cubic feet per day (nine acre-feet per year) of waste will be produced (see Table 89). Slag from the syngas furnaces will contain ash from the wood, diatomaceous

TABLE 88. SUMMARY OF ESTIMATED WASTEWATER EMISSIONS — WOOD TO OIL

Source	Estimated Flow	Pollutants		Emission Rate
Oily Process Condensates (after treatment)	94 gpm*	BOD	(<50 mg/l)	<60 lb/day
		TSS	(<10 mg/l)	<12 lb/day
		Oil & grease	(<20 mg/l)	<24 lb/day
		pH		6-9 units
Utility Water (includes cond's) (after treatment)	46 gpm	BOD	(<20 mg/l)	<14 lb/day
		TSS	(<10 mg/l)	<7 lb/day
		Oil & Grease	(<10 mg/l)	<7 lb/day
		pH		6-9 units
Boiler Blowdown and Regenerant Brines (after neutral and settling)	3 gpm	TSS	(<30 mg/l)	<1 lb/day
		TDS	(<500 mg/l)	<18 lb/day
		pH		6-9 units
Cooling Tower Blowdown (after settling)	2 gpm	BOD	**	**
		TSS	(<30 mg/l)	<1 lb/day
		TDS	(~1700 mg/l)	40 lb/day
		pH		6-9 units
Sanitary Wastewater (after treatment)	5 gpm	BOD	(<30 mg/l)	<2 lb/day
		TSS	(<30 mg/l)	<2 lb/day
		pH		6-9 units
Storm Runoff (30 inches per year)	Intermittent, 116 gpm ann. avg.	BOD	(<10 mg/l)	<20 lb/day
		TSS	(<50 mg/l)	<100 lb/day
		pH		6-9 units

* Most may be used as cooling tower makeup.

** Could have a high BOD concentration if treated wastewater used as cooling tower makeup. Cooling tower blowdown then would be biologically treated.

DISPOSAL SUMMARY -

TABLE 89. SOLID WASTE DISPOSAL SUMMARY — WOOD TO OIL

Source	Estimated Quantity	Potential Pollutants	Disposal
Syngas Slag Filter Cake	1,200 lb/hr at 50% solids	Char - potential hazardous organics, mineral ash, trace metals	720 cu ft/day buried in onsite landfill
Digester Centrifuge Cake	2,375 lb/hr at 20% solids	Organics, mineral ash, trace metals	Burned in utility boiler - residual as ash
Utility Boiler Ash	320 lb/hr at 90% solids*	Mineral ash, trace metals	380 cu ft/day buried in onsite landfill
Plant Trash	650 lb/day	Decomposable waste, oily materials, odor	100 cu ft/day buried in onsite landfill
Miscellaneous: Benfield Filter Cake, Water and Wastewater Basins Cleanouts	Intermittent	Organics, suspendable solids	Small amounts - buried

*Includes ash solids from combustion of digester centrifuge cake.

earth (filter aid), and some carbonaceous material (char). Composition of this char is not known. It is possible that hazardous organic compounds may be formed in the syngas partial oxidation process and may be retained in the char. If so, it may be more desirable environmentally to burn the char filter cake rather than to bury it, as assumed here. Burning the cake in the utility boiler would theoretically convert organic material to carbon dioxide and water. The fusion properties of the filter cake would need to be determined in order to evaluate potential slagging problems. The inorganic fraction of the filter cake — mainly wood ash and diatomaceous earth — will be predominantly mineral forms of silica, aluminum, calcium, magnesium, sodium, potassium, and iron. Trace quantities of nonvolatile heavy metals in the wood feed will also be present in the filter cake.

Disposal of the wet filter cake by proper landfill techniques will help to minimize contact with surface and groundwaters and prevent their pollution. Such techniques include preparation of an impervious base, diversion of drainage, and frequent application and compaction of cover material.

The digester centrifuge cake will contain the undigested organics and the inorganics that primarily originated from gas scrubbing; it will also contain bacterial cells from the digestion and activated sludge processes. This material will be fed along with wood to the utility boiler, and the noncombustible portion will be collected as flyash and bottom ash. The collected ash, mainly minerals, will be moisturized for transport and buried with the syngas filter cake and the general plant trash. The boiler ash as a solid waste will offer the least potential for harmful pollutant emissions. As with the filter cake and general plant trash, the burial in a landfill must be managed so that potential pollutants do not contaminate ground and surface waters.

Water and wastewater treatment basins will be subjected to periodic cleaning to remove accumulated solids. These solids, removed as sludges, will be deposited in the landfill. A small amount of filter cake from the Benfield solution filters will also be buried.

Plant solid wastes will contain organic and inorganic pollutants that could contaminate water resources. By proper landfill burial, these wastes are not expected to emit significant amounts of pollutants into the air or into water resources. The major impact of solid waste disposal will be the "consumption" of about 10 acres of land used for landfilling the wastes. Sections of the landfill site will be continuously stabilized and revegetated during the plant life.

Soils and Geology--Changes in the land surface will result from construction of the conversion plant as well as from disposal of the plant solid waste. Approximately 110 acres will be affected. Alterations of the land surface (during site preparation) would include removal of topsoil, changing local topography by cut and fill, grading and excavation for basins, diversion of natural drainage and construction of new drainage ways, and application of surfacing materials in process areas and roadways. During operation of the plant, the landfill disposal area will be increased in height by about 20 to 25 feet through emplacement of solid waste. The most significant impacts then will be the permanent alteration of the topography and the removal of productive soils.

However, these impacts will be minor since the loss of soil productivity will be a small fraction of the total in the region and there is nothing unique about the site topography.

Biological Effects--

Plant construction will disturb plant and animal life on the site itself and on adjacent land to some extent. Site clearing will remove most of the vegetation. Additional strips of about 110 acres of land will be cleared of vegetation for construction of the access road and rail spur. Timber on the site will be stockpiled for use later as plant feed. Most of the animals displaced by removal of their habitats will resettle nearby, but may suffer increased mortality due to overcrowding in habitats near carrying capacity. Generally, wildlife species do adapt to increased noise levels, although some species more sensitive to human presence or plant construction noise may be driven even further away. When the perimeter fence is completed, it will be a barrier to the movement of larger animals, while heavy traffic on the access road will be an intermittent hazard to all animals. Care in siting will ensure that no rare or endangered plant or animal species are present in the vicinity. Vegetation and woodland species are typical of those found in many areas of this region.

Secondary impacts on biological life forms will be similar to the other two biomass scenarios. No significant offsite damage to plants and animals is anticipated to result from construction or plant operation air emissions. Pollutants in the plant effluent discharge may harm aquatic organisms in the discharge mixing zone, but will have little adverse effect downstream. Runoff from severe storms could add a significant amount of suspended solids to the river when turbidity will already be high, thus increasing the stress on sensitive species. Intake of river water will result in damage or destruction of a small fraction of the small aquatic organisms in the river. Hydrocarbon spills in the plant are unlikely to result in any significant discharge. The product oil is not fluid and the solvent is relatively insoluble in water and not particularly toxic. Overall, the significant adverse impacts will be a direct result of clearing the site: (1) removal of vegetation, (2) displacement of wildlife, and (3) loss of productive forestland.

Aesthetic Impacts--

The hypothetical site is in an area of fairly high aesthetic quality because of the forested hilly terrain, good air and water quality, and low evidence of human use. The site itself is gently sloped, but visual access will be limited by the surrounding trees. The effect will be similar to encountering a large lumber or pulp mill by a road or river in the forest, as illustrated in Figure 35, though the conversion plant size and the general arrangement will be different.

The wood storage pile (covering 9 to 10 acres) will be the dominating physical feature, appearing as a low broad mound on an open level area. The processing portion of the plant is a symmetrical arrangement of the two trains. Rectangular process buildings will contrast with the horizontal and vertical cylindrical forms of exposed process equipment and storage tanks, all set on a level site. The Benfield columns, the boiler stack, and the flare stack will be the tallest structures at about 100 feet high.

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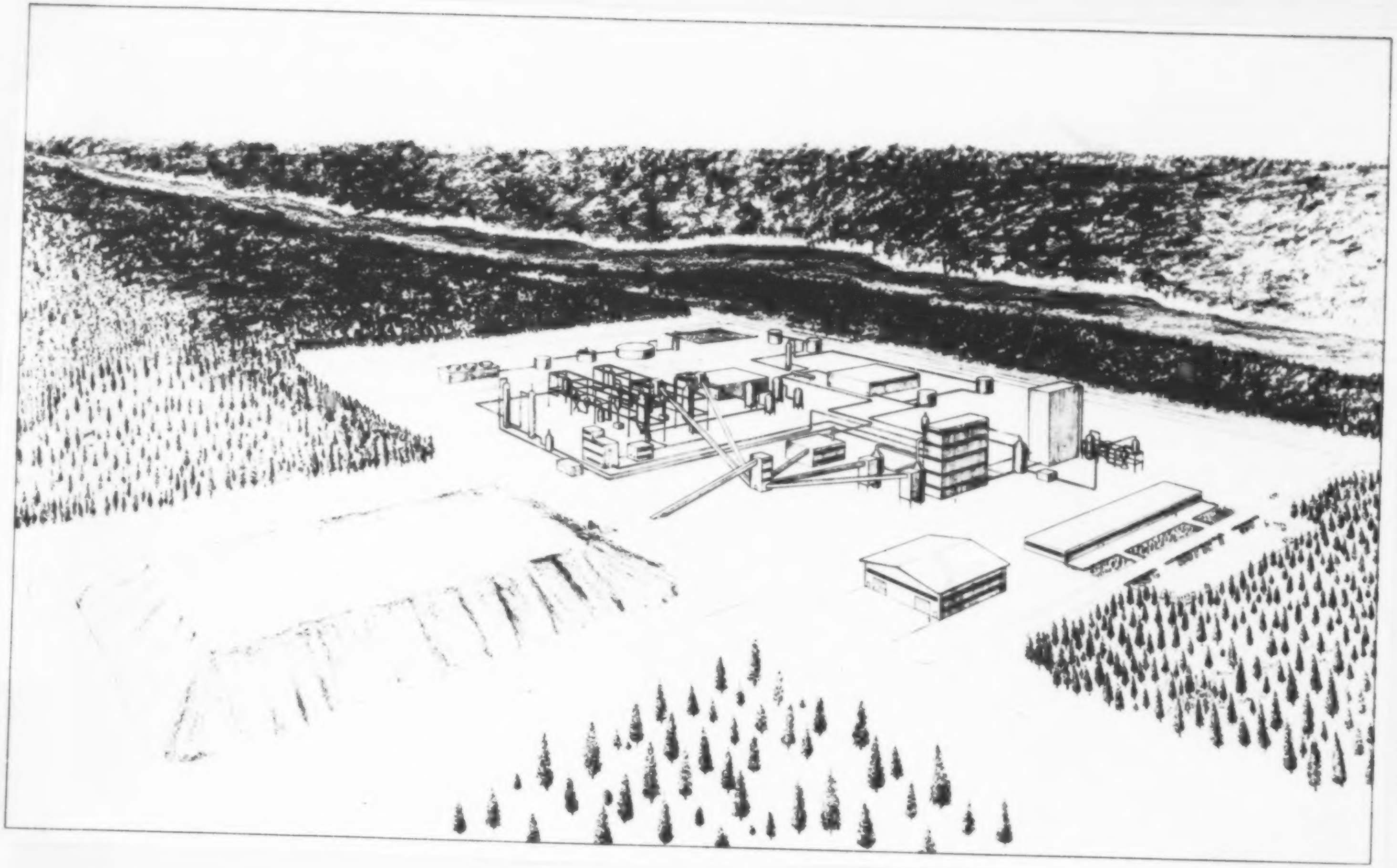

Figure 35. Artist's rendering of a commercial wood to oil plant.

Nonprocess buildings will be clustered near the plant entrance. The cooling tower plume, normally the only visible emission, may be discerned at some distance if the air is still.

The chemical plant appearance will contrast sharply with the woodland surroundings and will detract from the high aesthetic quality of the area, but the low visual accessibility will help to limit the number of adverse impressions.

Social and Economic Impacts--

The local economy will benefit from construction and operation of the wood-to-oil plant. The $99 million capital cost is a significant investment, and a portion of the construction and the annual operation funds will be expended in local communities. The local industrial tax base will be expanded and taxes on the facility will help to provide community services.

The plant will provide employment opportunities for local personnel — several hundred temporary jobs during the construction period and about 145 permanent jobs during its operating life. Since most of the construction and operation work forces will be obtained from the local manpower pool, little direct increase in population is anticipated and increased demands on community services by plant personnel should not strain the budgets of nearby communities. The plant itself will need supplemental fire protection services from local resources and about 18 MW of electrical power from local utilities. The projected generating capacity is considered adequate to supply the plant. In turn, the product oil can potentially serve as fuel to generate about 45 MW of electric power.

Thus, the demands of the facility can be absorbed by the local community without undue strain. The economic benefits derived from spending, wages, and taxes are expected to outweigh any adverse social impacts.

Table 90 summarizes principal impacts and potential mitigating measures anticipated for the wood-to-oil plant.

TABLE 90. SUMMARY ENVIRONMENTAL MATRIX — WOOD TO OIL

Environmental Factors	Effect of Plant Construction and Operation	Potential Mitigating Measures
Climatology and Meteorology	No discernible impact from plant construction or operation	
Air Quality	Potential minor short-term impact of fugitive dust from construction; minor adverse impact from plant operation	
Surface Water Availability	Minor adverse impact on quality; potential for generation of hazardous compounds uncertain and presence in plant effluent uncertain	Experimental work to assess potential problem
Groundwater Availability	No consumption, no effect	
Groundwater Quality	Little potential for degradation; ponds and basins lined; proper management of landfill site required	
Land Availability	Requires about 100 acres of land including 10 acres of landfill; no significant impact	Careful siting to avoid sensitive areas
Regional Ecology and Critical Habitat	About 100 acres of vegetation (mainly timber) removed and associated wildlife displaced or destroyed during construction; minor adverse impact; indirect impacts on vegetation and aquatic species	Careful siting to avoid critical wildlife habitats and rare or endangered species

(Continued)

TABLE 90 (Continued)

Environmental Factors	Effect of Plant Construction and Operation	Potential Mitigating Measures
Aesthetic Resources	Significant adverse impact in high aesthetic quality area, but limited visual accessibility	Retain vegetative boundary as screen, landscape plant areas
Historical, Archaeological Resources	Insignificant impact	Siting surveys to protect cultural resources
Community Economy	Significant benefit from construction and operation through local spending, wages paid and industrial tax revenue	
Community Population and Services	Small increase in population and residential services; little strain on ability of community to provide services	Plant to support community in expanding services if necessary
Labor Availability	Requirements for several hundred construction and about 145 operation personnel; local manpower resources adequate	Plant to train unskilled workers, as necessary
Power Availability	Requires about 18 MW (250 kWh/bbl) of electric power for plant operation; projected generating capacity adequate	Plant could generate required power with wood as fuel
Transportation Availability	Requirement for construction of access road and rail spur; small adverse impact on environment from new transportation corridors	Careful selection of corridors to minimize impacts on land use, ecology, water resources

COAL LIQUEFACTION PLANT SITE DESCRIPTION

The coal liquefaction plant is located in a hypothetical rural area in an eastern coal-producing state approximately two miles west of a major river.

Topography and Elevation

Locally the landscape is dominated by relatively high wooded hills (to 1400 feet) to the west of the fairly level upland plateau. The river valley just to the east is rather deeply dissected and is about 200 feet (MWL) below the mean site elevation of 1000 feet. No surface or underground mining has occurred on the site.

Transportation

A network of interstate and state highways surrounds the site area. A north-south interstate highway passes within five miles to the west. Common-carrier rail lines are located on either side of the river, which runs north-south. The river is navigable and heavily used for transport of bulk cargoes. Several small towns are located nearby, and a major metropolitan area is about 40 miles north of the site. An east-west products pipeline passes three miles south of the site.

Climate and Air Quality

The area has a typical continental type of climate with changeable temperatures, high humidity, and frequent precipitation. Table 91 summarizes principal climatic conditions at the hypothetical site. Temperatures exceed 90°F an average of 10 to 20 days per year and reach 32°F or lower an average of about 100 days per year. Total precipitation averages 42 inches annually, with the maximum occurring spring and summer.

The site area is located in EPA Region III, and the site county is currently listed as a nonattainment area for photochemical oxidants.

Land Use

The hypothetical plant site is mostly woodland and pastureland in private ownership. On the eastern edge of the site nearer the river, there is a small farm having cropland interspersed with dairy pasture.

Water Resources

River flow near the plant averages about 8000 cfs. The lowest recorded daily flow was about 200 cfs. The water quality is fair. In the past, this river basin has been significantly degraded by acid mine drainage, but there has been a gradual improvement in water quality over the past 25 years. The river is used for recreational fishing and boating. Average water quality characteristics are listed in Table 92. All of the plant makeup will be supplied from the river by an intake pumphouse and pipeline.

TABLE 91. ASSUMED CLIMATIC CONDITIONS AT THE SITE

Elevation:	1000 feet
Temperature:	
Annual Average	54°F dry bulb 49°F wet bulb
5-Percent Design Conditions	83°F dry bulb 73°F wet bulb
Annual Extremes (Daily)	-18°F to 99°F
Median of Annual (Winter) Extremes	-1°F
Prevailing Wind:	WSW at 4.2 mph
Precipitation:	
Annual Total	42 inches
Annual Runoff	18 inches
Annual Lake Evaporation	29 inches
10-year, 24-hour Storm	4.5 inches
Annual Frost-Free Period:	265 days

Soils

Soils on the plant site include the Inceptisols and Ultisols orders. Some portions have developed in clayey parent materials and are generally deficient in bases, which were removed primarily by leaching. The soils range from freely drained to poorly drained, and most still have a forest vegetation.

Vegetation

Most of the land area in the vicinity of the plant is farmland or woodland while the remaining, concentrated in river valleys, is industrial and municipal. The vegetative community consists of various succesional stages of a mixed forest dominated by hardwoods (primarily oak and hickory species). The area has typical understory shrubs and herbs, none of which is categorized as rare or endangered species.

TABLE 92. ASSUMED AVERAGE RIVER WATER QUALITY

Component	Value
Flow, Average (Daily)	8,089 cfs
Temperature	56°F
pH	7.0
Turbidity	13 JTU
Dissolved Oxygen	9.7 mg/l
Hardness (as $CaCO_3$)	124 mg/l
Alkalinity (as $CaCO_3$)	29 mg/l
Calcium	35 mg/l
Magnesium	9.7 mg/l
Sodium	24 mg/l
Potassium	2.7 mg/l
Iron	1.6 mg/l
Manganese	0.3 mg/l
Fluoride	0.2 mg/l
Chloride	15.3 mg/l
Sulfate	128 mg/l
Phosphate	0.4 mg/l
Nitrogen - Total	1.6 mg/l
Silica (as SiO_2)	5.1 mg/l
Total Dissolved Solids	252 mg/l

2nd

Wildlife

The hardwood forest and riparian woodland provide excellent habitat for birds, mammals, and invertebrates. Small game such as squirrels, rabbits, and pheasants are hunted locally. White-tailed deer are hunted to a lesser extent in the area. The bald eagle is the only endangered species known to inhabit the general area, though none has been observed on the site.

COAL PROCUREMENT

The H-Coal plant requires about nine million tons per year of coal. In this hypothetical scenario, the production from three large underground mines will be dedicated to supply the plant's feedstock. In this bituminous coal district, production averages about 25 million tons per year, nearly all by large-scale deep mining of the Pittsburgh seam. Two counties had nearly seven billion tons of in-place reserves as of 1970, virtually all in a seam thickness over 3½ feet (21).

The seam lies at a depth of 800 to 1500 feet and is reached by shaft entries. The mining height averages six feet. A relatively small amount of land area is occupied by the surface facilities at each mine. The underground mining plan is assumed to be similar for all three mines. Production and supply shafts are driven (at low cover) near the center of the lease holding. Main entries are driven along the center access with production headings driven to the left and right off the main heading. Production panels are developed parallel to the main heading and proceed outward from the main. The depth of the panels is about 2600 feet and is based on an eight-entry system, 16 feet wide on 95-foot centers.

Continuous mining units each produce about 350 tons of coal per shift. At full production, 42 production shifts are averaged per day (15-15-12) from a total of 17 mining units. The mines operate five days per week, 220 days per year. Each loading unit consists of a continuous miner, a loading machine, two shuttle cars, and a roof bolter. Shuttle cars dump coal into a feeder at the end of the unit belt conveyor. Coal is transferred by a series of belt conveyors to the bunkers at the foot of the production shafts. Automatic skip hoists bring the coal to the surface where it is conveyed to the preparation area. Shiploads of mine rock are diverted to the refuse disposal system (breaker reject bin).

The ROM coal undergoes only screening and primary crushing (plus 3-inch material) for mine rock rejection and size control (also tramp iron removal by magnetic separators). The 3-inch by 0 material is conveyed to 10,000-ton capacity silos from which it is loaded into unit trains for shipment to the plant. The mines employ floodloading of 120-car, 100-ton capacity unit trains at the rate of 3000 tons per hour. On the average, one unit trainload is shipped from each mine five days a week. Two of the three mines ship a unit trainload on Saturday for a total of 17 unit train shipments per week.

Mine water in two of the three mines is acidic enough to require treatment for iron removal before discharge. The other mine has good quality mine water and uses much of it at the mining faces for dust control. The remainder is pumped

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to the surface and discharged after passing through a small holding basin. Conventional acid mine drainage systems treat the acidic water — lime neutralization, aeration, primary clarification, and secondary settling of solids in a polishing pond.

At each of the three mines, mine rock and refuse from the rotary breaker are conveyed overland to a disposal site. This coarse material is dumped, spread, and compacted. The disposal areas are assumed to be shallow valleys that are ultimately filled with the reject materials, and the disposal plans include drainage control, erosion control, and revegetation schemes.

On the order of 30,000 acres of surface will be needed by the mines to produce the required tonnage for the plant over its 20-year life.

The acres of surface land actually used by the mines for surface facilities and reject disposal will be much less than the underground mine acreage.

COAL LIQUEFACTION PROCESS DESCRIPTION (H-COAL)

The coal liquefaction facility described in this section is based upon the use of the H-Coal^{R} Process developed by Hydrocarbon Research, Inc.

The facility is designed to convert approximately 9.1 million tons per year of high-sulfur Eastern coal into a low-sulfur fuel oil product as well as a low-sulfur naphtha product.

The fuel oil production rate is 51,325 barrels per stream day. The fuel oil sulfur content and gravity are 0.5 wt percent and -1.8° API respectively. The naphtha production rate is 15,531 BPSD. The sulfur content and gravity of the naphtha product are 0.02 wt percent and 38.2° API respectively.

In addition to the major products, the following byproducts are also produced:

- 1052.2 LTPSD of sulfur flakes
- 180.2 TPSD of liquid ammonia
- 17.9 TPSD of mixed phenols
- 4 MW of electrical power for export

The plant site (fenced area) occupies approximately 440 acres, but an additional 440-acre buffer zone is assumed to surround the plant. Figure 36 shows the general plant layout. Coal is assumed to be delivered to the plant by unit train on a contract dollars-per-ton-delivered basis.

Design Bases

The conceptual plant process design presented in this section is based upon the design work performed by Fluor Engineers and Constructors, Inc. for the ERDA Fossil Energy Division with only balance-of-plant (nonprocess) modifications made to reflect the different hypothetical plant location.

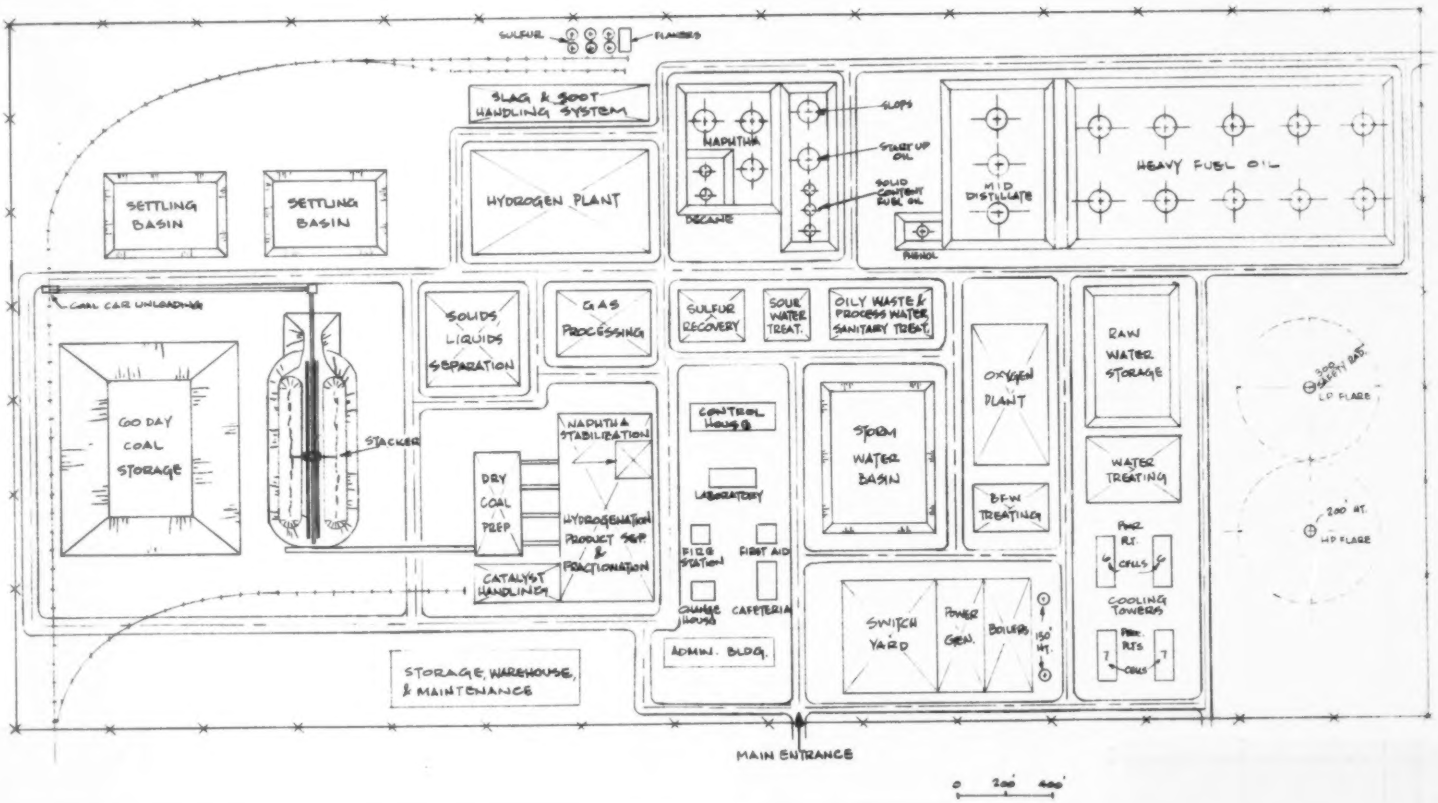
SULFUR
FLARES
SLAG & SOOT HANDLING SYSTEM
SETTLING BASIN
SETTLING BASIN
HYDROGEN PLANT
NAPHTHA
DECANE
SLOPS
START UP OIL
SOLID CONTENT FUEL OIL
MID DISTILLATE
PHENOL
HEAVY FUEL OIL
COAL CAR UNLOADING
60 DAY COAL STORAGE
STACKER
SOLIDS, LIQUIDS SEPARATION
GAS PROCESSING
SULFUR RECOVERY
SOUR WATER TREAT.
OILY WASTE & PROCESS WATER SANITARY TREAT.
OXYGEN PLANT
B.F.W. TREATING
RAW WATER STORAGE
WATER TREATING
300' SAFETY RAD.
LP FLARE
200' HT.
HP FLARE
PWR. PLT. CELLS
COOLING TOWERS
PRC. PLTS CELLS
NAPHTHA STABILIZATION
DRY COAL PREP
HYDROGENATION PRODUCT SEP. & FRACTIONATION
CATALYST HANDLING
CONTROL HOUSE
LABORATORY
FIRE STATION
FIRST AID
CHANGE HOUSE
CAFETERIA
ADMIN. BLDG.
STORM WATER BASIN
SWITCH YARD
POWER GEN.
BOILERS
150' HT.
STORAGE, WAREHOUSE, & MAINTENANCE
MAIN ENTRANCE
0
200'
400'

Figure 36. H-coal liquefaction plant, plot plan.

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The specific reference material used in this evaluation is (7):

> H-Coal Commercial Evaluation, Conceptual Design and Economic Analysis for a 25,000 Ton-per-Day H-Coal Liquefaction Plant, Case-I Fuel Oil Mode, prepared by Fluor Engineers and Constructors, Inc., for the United States Energy Research and Development Administration, under contract No. E(49-18)-2002, March 1976, final unpublished report.

Table 93 presents the composition of the assumed coal feedstock for the plant, which is the same as that used in the Fluor report (7).

TABLE 93. COAL FEEDSTOCK PROPERTIES (7)

Composition	As Received	Ultimate Analysis
Carbon, % wt	63.48	70.50
Hydrogen, % wt	4.81	5.40
Nitrogen, % wt	0.86	0.95
Oxygen, % wt	7.28	8.10
Sulfur, % wt	4.45	4.90
Moisture, % wt	10.00	0.00
Ash, % wt	9.12	10.15
	100.00	100.00
Calculated HHV, Btu/lb	11,900	
Calculated, LHV, Btu/lb	11,445	

Table 94 presents the general design bases assumed for the conceptual plant.

The process descriptions, which follow, describe the major process facilities which are depicted on the simplified block flow diagram, Figure 37. Table 95 presents the compositions of the major process streams identified on the block flow diagram. Additional process details are available in the Fluor report (7).

TABLE 94. COAL TO FUEL OIL DESIGN BASES AND ASSUMPTIONS

Plant Capacity	The design capacity of the commercial plant is based upon the conversion of 25,000 STPD of dry bituminous high sulfur coal into low sulfur fuel oil
Coal Receiving	Unit train delivery and transported into the processing facilities by conveyor belt
Onsite Coal Storage	60 days dead,* 3 days live
Coal Feed Preparation	Four 33% grinding, drying and classifying systems have been provided
Coal Liquefaction	Six parallel-case slurry preheaters and ebullated reactors are provided. The number of parallel trains was set by imposing a maximum vessel diameter of approximately 15 feet. This diameter permits shop fabrication and use of rail shipping facilities
Product Separation and Recovery	The following number of parallel trains have been provided for the liquid product separation and recovery: Liquid processing - 7 Naphtha stabilization - 1 Slurry flashing and stripping - 2 Solvent deashing - 7
Gas Processing and Recovery	The following number of parallel trains have been provided for gas processing and recovery: Hydrogen compression - 3 High-pressure absorption - 3 Low-pressure absorption - 3
Oxygen	5400 TPD of oxygen is required having a purity of 97 volume percent. Three 1800 TPD trains have been provided
Aqueous Effluent	Maximum cleanup and reuse of process wastewaters, water treatment wastes, and contaminated storm runoff. Excess storm runoff discharged to river. High TDS aqueous blowdowns sent to aqueous waste disposal system (undefined in Fluor report) - assumed to be evaporative concentration *
Solid Waste Disposal	Soot and slag wastes hauled by rail car to contractor-operated landfill site for disposal in valley fill operation *

(continued)

TABLE 94. (Continued)

Gas Effluent	All gaseous effluents from the plant will meet the prevailing federal and state standards†
Plant Water Supply	River water (pumphouse intake system*)
Onsite Water Storage	3-day storage capacity*
Plant Load Factor	91.3 percent
Plant Operating Life	20 years

* Balance-of-plant modifications different from Fluor report.

† Treated tail gas from the Claus unit, as designed (1975), does not meet NSPS for sulfur recovery units (Petroleum Refining, 40CFR 423, Subpart J – March, 1978)

TABLE 95. H-COAL LIQUEFACTION PLANT — 25,000 TONS PER DAY — OVERALL MATERIAL BALANCE

Stream No.	1		2	3	4	5	6	7	8	9
Description	Process Coal MPH		Recycle Hydrogen MPH	Makeup Hydrogen MPH	Heavy Dist. Recycle MPH	Hydroclone Overhead MPH	Oxygen Feed MPH	Slurry Gasifier MPH	Naphtha Product MPH	Heavy Fuel Oil Product MPH
C	12,915.5	N_2 + Ar	3,819.0	577.5	—	3.8	418.9	—	—	
H_2	55,919.0	O_2	—	—	—	—	13,614.3	—	—	
N_2	715.1	CO	1,642.4	900.4	—	1.5	—	—	—	
O_2	5,285.7	CO_2	621.8	148.5	—	2.7	—	—	—	
S	3,228.7	H_2S	433.4	—	—	4.5	—	—	0.3	
Moisture	2,165.7	NH_3	—	—	—	1.3	—	—	—	
MPH	190,229.7	H_2O	32.8	36.9	117.3	—	—	7.5	0.5	61.4
lb/hr	1,918,290	H_2	53,376.7	41,572.6	—	44.6	—	—	—	
Ash lb/hr	211,960	C_1	6,678.8	197.4	—	13.1	—	—	—	
TOTAL lb/hr	2,130,250	C_2	971.9	—	—	8.5	—	—	—	
		C_3	334.8	—	—	6.2	—	—	1.6	
TPSD	25,563	C_4	98.0	—	—	4.4	—	—	42.2	
		C5-400°F	43.0	—	—	131.0	—	1.1	1,764.9	1.2
		400-500°F	—	—	393.6	183.6	—	1.6	4.3	360.6
		500-975°F	—	—	6,166.1	5,855.4	—	174.5	—	1,821.5
		975+$^\circ$F	—	—	0.1	2,341.7	—	403.9	—	550.9
		n-C_{10}	—	—	—	—	—	26.4	16.0	0.2
		MPH	68,052.6	43,433.3	6,677.1	8,602.3	14,033.2	615.0	1,829.8	2,795.8
		lb/hr	463,650	133,656	1,346,005	2,874,726	451,650	328,747	189,096	816,203
		Solids lb/hr	—	—	—	319,385	—	331,425	—	885
		TOTAL lb/hr	463,650	133,656	1,346,005	3,194,111	451,640	660,172	189,096	817,088
		GPM-60°F	—	—	2690	5614	—	1043	453	1497
		SCFM	430432	274716	—	—	88761	—	—	—

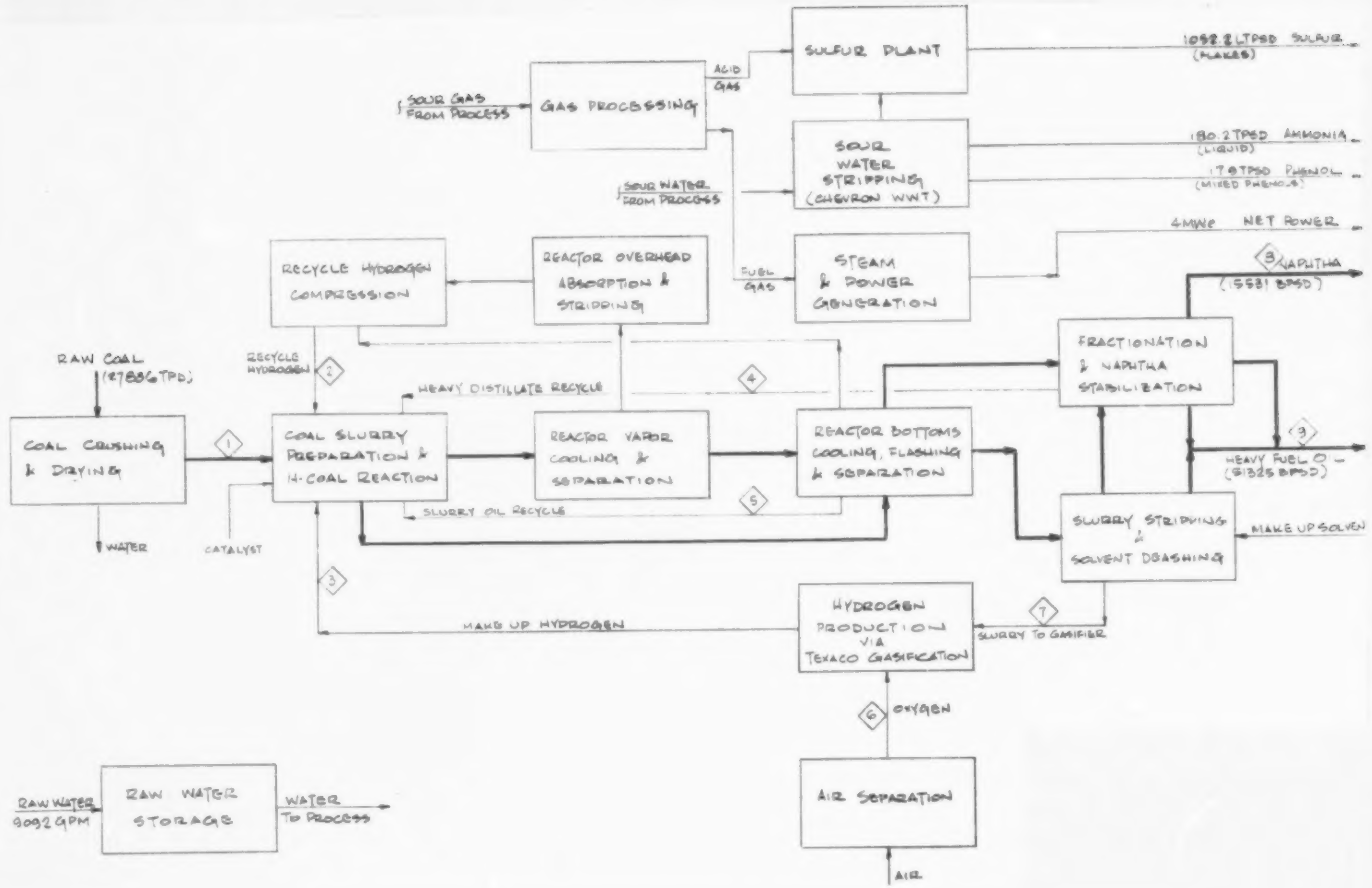
SULFUR PLANT
GAS PROCESSING
SOUR GAS FROM PROCESS
ACID GAS
1052.2 LTPSD SULFUR (FLAKES)
SOUR WATER STRIPPING (CHEVRON WWT)
SOUR WATER FROM PROCESS
180.2 TPSD AMMONIA (LIQUID)
17.8 TPSD PHENOL (MIXED PHENOLS)
FUEL GAS
STEAM & POWER GENERATION
4 MWe NET POWER
RECYCLE HYDROGEN COMPRESSION
REACTOR OVERHEAD ABSORPTION & STRIPPING
8 NAPHTHA (15531 BPSD)
RAW COAL (27886 TPD)
RECYCLE HYDROGEN
2
HEAVY DISTILLATE RECYCLE
4
FRACTIONATION & NAPHTHA STABILIZATION
1
COAL CRUSHING & DRYING
COAL SLURRY PREPARATION & H-COAL REACTION
REACTOR VAPOR COOLING & SEPARATION
REACTOR BOTTOMS COOLING, FLASHING & SEPARATION
9
HEAVY FUEL OIL (51325 BPSD)
SLURRY OIL RECYCLE
5
WATER
CATALYST
SLURRY STRIPPING & SOLVENT DEASHING
MAKE UP SOLVENT
3
7
HYDROGEN PRODUCTION VIA TEXACO GASIFICATION
MAKE UP HYDROGEN
SLURRY TO GASIFIER
6
OXYGEN
RAW WATER 9092 GPM
RAW WATER STORAGE
WATER TO PROCESS
AIR SEPARATION
AIR

Figure 37. H-coal liquefaction plant, simplified block flow diagram.

Coal Handling

Coal is delivered to the plant by unit train (average 100-ton capacity, 120-car trains). Seventeen unit train deliveries per week will provide a total of 204,000 tons per week of coal. This quantity of coal is sufficient for around-the-clock operation in the coal preparation unit. A three-day live storage pile and a 60-day dead storage pile have been provided. The car dump facility transfers coal at a 3000-tph capacity to the stacking conveyors at the live storage pile. Coal is reclaimed by the use of two parallel 48-inch conveyors.

Coal Crushing and Drying

Three operating Loesche Mills and one spare have been provided, each having a capacity of 400 tph. The Loesche Mills are capable of grinding, drying, and classifying in one operation. Flue gases from fuel-gas-fired heaters dry the coal. Cyclone collectors and wet scrubbers remove particulates from the gases before discharge. The dried sized coal is transferred to the slurry preparation area via Fuller-Kinyon pumps and a dense phase conveying system. Condensate from coal drying is sent to the plant water system.

Coal Slurry Preparation and H-Coal Reaction

Coal slurrying is performed in 12 parallel trains. In each slurry vessel the feed coal is mechanically mixed with hot slurry oil consisting of heavy distillate and slurry oil recycles.

The coal-oil slurry is then pumped to reactor pressure, mixed with recycle and makeup hydrogen (about 263 MSCFM makeup), preheated, and charged to one of the six reactors operating in parallel. Each reactor has its own slurry and hydrogen heaters. Four reciprocating charge pumps are required for each reactor.

The hydrogenation of the coal is accomplished in an ebullated reactor which is designed to operate at 3000 psig and 850°F. At these conditions, more than 90 percent of the coal is liquefied. Each reactor is equipped with a pump, located internally, providing sufficient liquid recirculation to maintain the catalyst in an ebullated state and to maintain essentially isothermal conditions across the reactor. Catalyst addition and removal facilities are provided to permit continuous reactor operation. Each ebullated reactor has a 13-foot 10-inch ID and a 39-foot 0-inch (T-T) dimension.

The reactor vapor and liquid products containing the unreacted coal and ash are discharged from the reactor in a common stream, passed to the reactor in a common stream, and then passed to the reactor vapor-liquid separators.

Reactor Vapor Liquid Separation Recovery

The product separation area has two main design objectives. The first objective is to produce an intermediate-pressure hydrogen-rich stream for recycle to the reactors. The second objective is to process the liquid product, containing unreacted coal and ash, to yield a solids-free fuel oil for fractionation, a slurry stream for the coal slurry operation, and a slurry stream containing the net unreacted coal and ash.

The slurry leaving the reactor vapor-liquid separator is subjected to a series of cooling and pressure-reduction steps. The pressure reductions produce the recycle hydrogen as well as a hydrocarbon distillate stream. The slurry leaving the final low-pressure flash is led to a battery of hydroclones for further solids concentration. Three trains, each containing 35 hydroclones, are employed (27 operating, seven spares). Each hydroclone is rated at approximately 130 gpm and operates with a pressure drop of 60 psig. The overhead from the hydroclones is recycled back to the coal slurrying operation, while the hydroclone bottoms are sent to the solvent deashing area for further processing.

Slurry Stripping and Solvent Deashing

The feed to this process is the hydroclone bottoms. This unit separates heavy hydrocarbon fractions from the unreacted coal and ash. The hydrocarbon fractions are removed primarily by common physical methods such as flashing and steam stripping followed by a gravitational separation of the solids by solvent precipitation. The antisolvent used in this step is normal decane.

Three basic products result from this process operation. The primary product is a heavy fuel oil which represents 80 percent of the overall facility output. Secondary products are a light ends fraction which is further processed in the naphtha stabilization section, and a heavy residuum fraction. The heavy residuum fraction is used as the basic feedstock to the hydrogen plant.

The stripping and deashing operations are large and require multiple parallel trains.

The stripping section consists of two trains, while the solvent deashing section contains six trains, each train consisting of six parallel first-stage settlers.

Fractionation and Naphtha Stabilization

The feeds to the fractionation section are the distillate from the reactor vapor-liquid separation step, and the slurry flash and light ends from the solvent deashing step (113,864 BPSD of liquids and 15.47 MMSCFD of vapor). There are three steps in the processing scheme. These steps include:

- Preheating of the feed to the fractionator
- Separation of the feed into naphtha (15,531 BPSD), middle distillate (5211 BPSD), and heavy distillate (102,960 BPSD)
- Stabilization of the naphtha

The fractionation section consists of three trains, and the stabilization section is a single train. The primary product of this unit is the production of the remaining 20 percent of the fuel oil product. This product is combined with the output from the solvent deashing unit, and the combination represents the final fuel oil product (51,325 BPSD) which is sent to storage tanks.

Reactor Overhead Absorption and Stripping

This unit consists of a high-pressure lean oil absorption system for the recovery of heavy hydrocarbons and the separation of the hydrogen-rich recycle gas (337.6 MSCFM hydrogen).

Gas Processing

This unit processes a combined feed of the sour gases produced in various areas of the plant. The sour gases are scrubbed in a low-pressure absorber with a 65 wt percent diglycolamine (DGA) solution. The absorber overhead gas contains only a trace of hydrogen sulfide and carbon dioxide. The regenerator overhead contains all of the acid gas and becomes the feed to the sulfur plant (19.0 MMSCFD).

Hydrogen Plant

This plant furnishes 396 MMSCFD of hydrogen (95.8 percent H_2), which is used in the H-coal process for the hydrogenation of coal.

The Texaco Partial Oxidation Process is used to gasify the heavy residuum from the solvent deashing step and produce a hydrogen synthesis gas. The heavy residuum, containing approximately 50 wt percent solids, is gasified in the presence of 5400 tpd of oxygen.

The resulting synthesis gas is cooled and further processed in a shift conversion reactor. This is a catalytic step which converts carbon monoxide to hydrogen. The resulting shifted gas now contains principally hydrogen, carbon dioxide, water, and hydrogen sulfide.

The shifted gas is then processed in a Selexol unit. The Selexol process is an acid gas removal process offered by the Allied Chemical Co. The product from a Selexol unit is a high-purity, dry, hydrogen stream. The product hydrogen is then compressed up to 2350 psig and fed to the H-coal reactors. The other streams produced in the Selexol unit are a carbon-dioxide-rich gas vented to the atmosphere; a hydrogen-sulfide-rich gas, which is fed to the sulfur plant; and sour gas, which is fed to the sour water stripping unit. The CO_2 vent gas will contain some hydrogen sulfide, carbonyl sulfide, and nonmethane hydrocarbons. It is probable that this stream may need to be scrubbed or incinerated before release to the atmosphere.

Sour Water Stripping

The purpose of the sour water stripping unit is to separate and recover ammonia from sour water and to obtain a hydrogen sulfide stream suitable for feeding to a Claus sulfur plant.

The process employed for this application is the Chevron WWT process. This process is offered by Chevron Research.

The products from this unit are:

- Liquid agricultural grade ammonia
- Water effluent (1810 gpm) containing 50 ppmw ammonia, 5 ppmw hydrogen sulfide, and phenols
- Hydrogen-sulfide-rich gas containing a maximum of 50 ppmw ammonia

Sulfur Recovery

The sulfur plant takes the hydrogen-sulfide-rich streams from the gas processing, hydrogen, and sour water stripping units and produces elemental sulfur in a conventional Claus plant. Three 50-percent capacity sulfur plants are provided. The total sulfur production rate is about 1052 LTPSD. A tail gas treating process is also provided for each sulfur plant. The Claus plant has been designed to achieve 96 percent overall recovery of hydrogen sulfide as elemental sulfur. The inclusion of a tail gas treating process increases the overall recovery to 99 percent. Cleaned tail gas streams are discharged to the atmosphere through a common stack.

Auxiliary Systems

Oxygen Plant--

The oxygen plant is a conventional air separation plant designed to supply 5400 tpd of oxygen (as 100 percent). Three 1800-tpd trains are provided. The oxygen product is used as a gasification reactant in the hydrogen plant.

Steam and Power Generation--

The H-coal process does not recover enough high-pressure steam from the process to satisfy all motive and process steam requirements.

Two boilers are provided with a combined generating capacity of 1.8 million pounds per hour of 1500 psig steam. The boilers are fired with sulfur-free process offgas delivered by the fuel gas system. Three 50-percent turbogenerators have been provided. The installed capacity is 90 MWe with a normal demand of 60 MWe. Two 150-foot-high stacks discharge boiler flue gases to the atmosphere.

Product Storage and Loading--

This unit is designed for the storage of liquid products. Naphtha, middle distillate, and heavy fuel oil together with recovered byproducts (all produced in the process units) are stored, before delivery to industrial customers. Intermediate storage is provided for slops, solids-content fuel, and liquid products (startup oil, n-decane) purchased from outside sources for startup and makeup.

Sulfur is stored as solid flakes in silos at the railroad. Naphtha and fuel oil are shipped by pipeline; all other material is shipped by tank cars. The pipelines are outside the scope of this study.

The pumpout rate for naphtha and middle distillate is 1000 gpm, while the pumpout rate for fuel oil is 2500 gpm.

Twenty-one-day storage capacity is provided for liquid hydrocarbon product and ammonia. For all other intermediates and byproducts, the storage capacity is as required by the process. The sulfur silos are sized for seven days of storage.

Flare System and Stacks--

A relief system is provided to protect the process equipment from over-pressure in conformance with accepted practice. It is assumed that a dual relief system would be provided for this plant. One system will be provided for high pressure and one system for low pressure. Relief lines will carry away process fluids from the processing areas to the elevated flare stacks, where ignition will occur in case of release. Separator drums are provided at the base of each stack to capture liquids which are then pumped to slops storage. Molecular seals are provided in each stack to prevent air intrusion into the relief system.

Water Systems--

Figure 38 presents a simplified diagram of the H-coal water system. The plant makeup water demand is about 9100 gpm (9092 gpm design average). Maximum supply capacity is 16,000 gpm from three 33-percent capacity pumps in the intake pumphouse. River water is pumped through a 24-inch diameter line to the onsite storage pond. This 39-million-gallon earthen basin provides three days of makeup (design capacity). River water is used for cooling-tower makeup, fire water, potable water, utility water, process water, and boiler feedwater makeup. Three pondwater pumps supply makeup water to the cooling towers (5073 gpm) and water (3694 gpm) to granular media filters for suspended solids removal prior to additional treatment. Additional pondwater pumps feed the potable and utility water systems.

Pondwater is treated in a packaged system for filtration and chlorination to produce about 125 gpm of potable quality water. An air-pressurized surge tank is provided for distributing water throughout the plant. About 200 gpm of pondwater is supplied to the utility distribution system. Utility water losses from miscellaneous use are estimated at 50 gpm.

Boiler feedwater treatment consists of reverse osmosis (RO) followed by mixed-bed ion exchange or polish demineralization. Micron filter units precede the RO membrane modules to remove fine particulate matter, helping to minimize membrane fouling. RO product (about 90-percent recovery) contains 40 to 50 mg/1 TDS, and 1810 gpm is used for makeup to the process units. Much of the process water is recovered as stripped sour water.

The mixed bed units produce 1400 gpm of boiler feedwater makeup with a TDS level of two mg/1 of less. The granular media filter and micron filter backwashes and the RO concentrate brine are collected for treatment and reuse in the cooling water system. The low TDS backwash and rinse waters from ion exchange regeneration are fed back to the RO system ahead of the micron filters. High TDS acid and caustic regenerant wastes are neutralized.

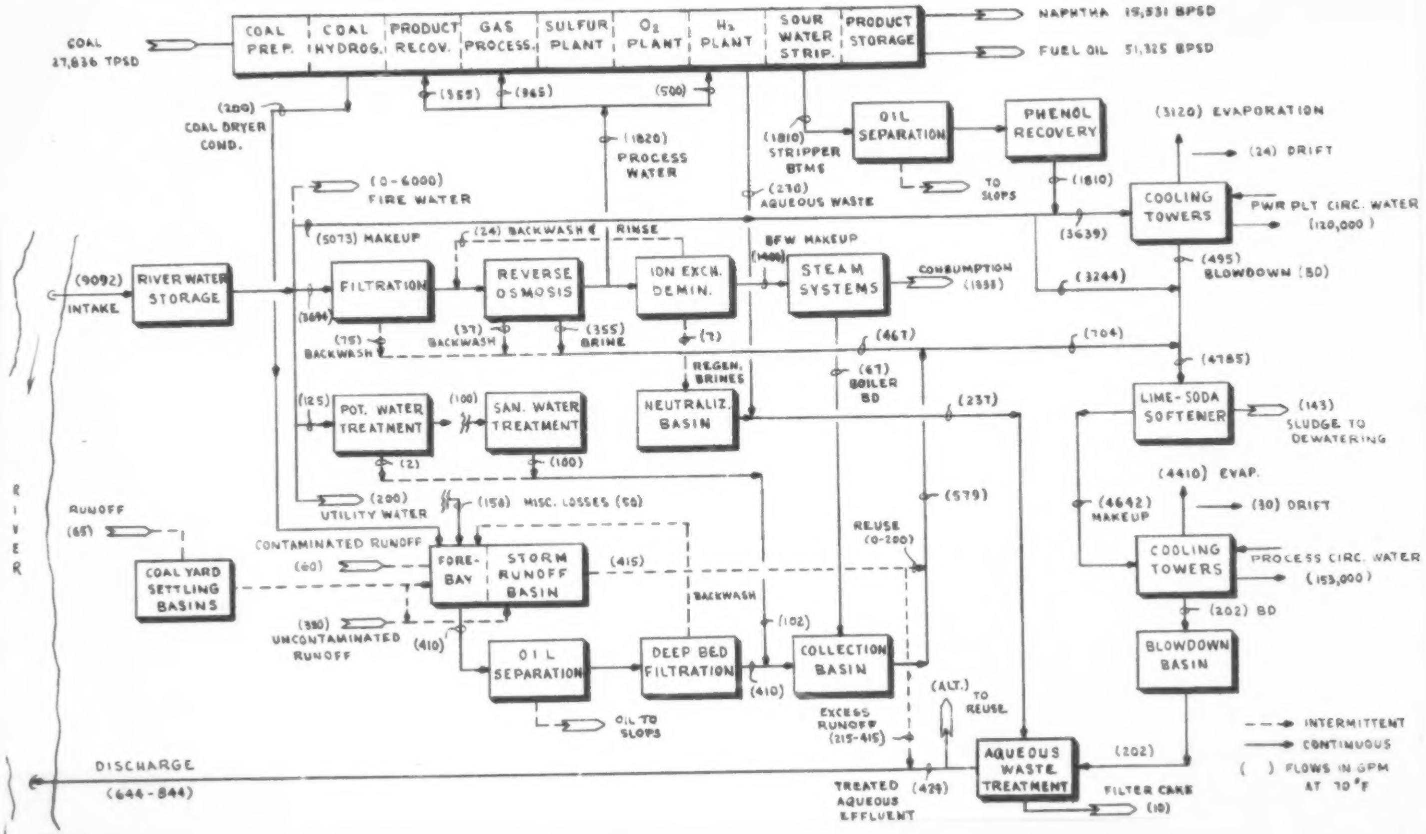
COAL 27,836 TPSD
COAL PREP.
COAL HYDROG.
PRODUCT RECOV.
GAS PROCESS.
SULFUR PLANT
O2 PLANT
H2 PLANT
SOUR WATER STRIP.
PRODUCT STORAGE
NAPHTHA 15,531 BPSD
FUEL OIL 51,325 BPSD
(355)
(965)
(500)
(200) COAL DRYER COND.
(1820) PROCESS WATER
(1810) STRIPPER BTMS
(230) AQUEOUS WASTE
OIL SEPARATION
TO SLOPS
PHENOL RECOVERY
(1810)
(3120) EVAPORATION
(24) DRIFT
COOLING TOWERS
PWR PLT CIRC. WATER (120,000)
(3639)
(495) BLOWDOWN (BD)
(3244)
(0-6000) FIRE WATER
(5073) MAKEUP
(24) BACKWASH
RINSE
BFW MAKEUP
(1400)
(9092) INTAKE
RIVER WATER STORAGE
FILTRATION
(3694)
REVERSE OSMOSIS
ION EXCH. DEMIN.
STEAM SYSTEMS
CONSUMPTION (1333)
(75) BACKWASH
(37) BACKWASH
(355) BRINE
(7)
(467)
(704)
(4785)
REGEN. BRINES
(67) BOILER BD
(125)
POT. WATER TREATMENT
(100)
SAN. WATER TREATMENT
NEUTRALIZ. BASIN
(237)
LIME-SODA SOFTENER
(143) SLUDGE TO DEWATERING
(2)
(100)
(200) UTILITY WATER
(158)
MISC. LOSSES (50)
(579)
(4410) EVAP.
(4642) MAKEUP
(30) DRIFT
R I V E R
RUNOFF (65)
COAL YARD SETTLING BASINS
CONTAMINATED RUNOFF (60)
FORE-BAY
STORM RUNOFF BASIN
(415)
REUSE (0-200)
COOLING TOWERS
PROCESS CIRC. WATER (153,000)
BACKWASH
(330) UNCONTAMINATED RUNOFF
(410)
(102)
(202) BD
OIL SEPARATION
DEEP BED FILTRATION
(410)
COLLECTION BASIN
BLOWDOWN BASIN
OIL TO SLOPS
EXCESS RUNOFF (215-415)
(ALT.) TO REUSE
AQUEOUS WASTE TREATMENT
(202)
DISCHARGE (644-844)
TREATED AQUEOUS EFFLUENT (429)
FILTER CAKE (10)
INTERMITTENT
CONTINUOUS
( ) FLOWS IN GPM AT 70°F

Figure 38. H-coal plant, simplified water balance.

Steam pressure levels in the plant include 1500 psig, 600 psig, 150 psig, and 50 psig. Two process fuel-gas-fired boilers produce 1500 psig, 900°F steam for power generation. Saturated 1500 psig steam from hydrogen plant steam generation is superheated in a fuel-gas heater to provide additional steam supply to the turbine generators. Turbine exhause steam is condensed and returned to the condensate distribution system. Other process steam generators produce 50 and 150 psig steam for process and utility use. Process and utility steam consumption and losses total 1333 gpm. Steam generator blowdown streams total 67 gpm; the blowdowns are collected for reuse in the cooling water systems. Boiler water conditioning chemicals include hydrazine, morpholine, and sodium phosphates.

Two separate cooling water systems are provided, one for the power plant and the second for the process units. The cooling systems are operated in a cascade mode, with blowdown from the power-plant system softened and used as makeup to the process cooling system.

The design circulation rate for the power-plant cooling water is 120,000 gpm. Two six-cell induced draft cooling towers cool the hot-side condenser return water to 85°F. Evaporation and drift losses total 3144 gpm. The towers are operated at about seven cycles of concentration (about 1700 mg/l TDS). Makeup is about half river water and half treated process effluent from sour water stripping (Chevron WWT process).

The process cooling water circulation rate is about 153,000 gpm (design). Two seven-cell towers reject the process heat load to the atmosphere with tower evaporation and drift losses of 4400 gpm. Makeup to this system is a lime-soda softened combination of river water (3244 gpm), cooling tower blowdown (495 gpm), water treatment wastes (467 gpm), and wastewaters (579 gpm) including storm runoff. Lime-soda softening of the makeup reduces the hardness enough to permit operation at high (up to 20) cycles of concentration without unmanageable scaling of the heat transfer surfaces. Circulating water TDS levels on the order of 10,000 mg/l are maintained. Blowdown is combined with other high TDS streams for final effluent treatment. Both cooling water systems use sulfuric acid for pH control and proprietary chemicals for corrosion inhibition, scale control, and sludge dispersion. Biological fouling is controlled with chlorine.

The plant wastewater treatment systems are designed primarily to clean up effluents for reuse.

Storm runoff from process and hydrocarbon tankage areas is collected in storm sewers and sent to the forebay section of a 35-million-gallon storm basin. The basin can impound about three inches of runoff from the entire plant site (440 acres). Normally only the first portion (contaminated) of the rainfall runoff is directed to the forebay; the remainder is diverted to the main basin. Utility wastewaters and condensate from the coal dryer system are also directed to the forebay section. Storm runoff from plant areas where contamination will not occur flows directly to the main basin.

Two seven-million-gallon settling basins accept runoff from the coal storage yard (56 acres). Runoff contacting the dead and live piles, as well as surfaces around the piles. may pick up significant amounts of coal dust. Prolonged contact with the coal may also result in leaching of contaminants. The basins not only provide suspended solids settling capacity, but also can impound a significant volume of contaminated drainage for either treatment of workoff at a low rate through the main storm basin. At an annual runoff of 25 inches (42 inches precipitation) over 400 acres of drained plant area, the runoff volume would average 516 gpm on a continuous basis. Up to 200 gpm can be pumped from the main basin to the softener unit. Excess runoff is discharged to the river.

Contaminated runoff from the forebay is treated in a gravity oil/water separator, either API or CPI (corrugated plate interceptor) type. Skimmed oil is pumped to slop tanks for recovery. Settled sludge is pumped periodically to a hold tank for subsequent dewatering. Effluent water from the separator is treated in a deep bed filtration unit for additional oil and suspended solids removal. Filter backwash is returned to the forebay of the storm basin. Filtered effluent (40 gpm average) is collected in a basin with other wastes (treated sanitary wastewater, boiler blowdown, and potable water filter backwash) for pumping to the lime-soda softener.

Sanitary sewage (100 gpm) is treated in a package unit which employs extended aeration, biological treatment, clarification, tertiary filtration, and disinfection. Effluent is sent to the wastewater collection basin.

The main process effluent is 1810 gpm of wastewater from the Chevron WWT unit. Flotable oil which may be present is recovered in an oil/water separator. This unit is follow by a phenol recovery system to remove dissolved hydrocarbons, principally phenols. The recovery process employs polymeric adsorbent resin. The resin beds are regenerated with acetone and the crude (mixed) phenols are recovered by distillation. The cleaned process effluent (containing small amounts of ammonia and phenol) is combined with raw water for reuse as makeup to the power plant cooling tower.

The plant effluents consist of cooling tower blowdown* (202 gpm), ion exchange regenerant brines* (7 gpm), and aqueous waste* (230 gpm) from the hydrogen plant — in addition to excess stormwater (during heavy rainfall periods). If these normally high TDS plant effluents were free of contaminants other than salinity, they might be discharged to the river with little impact. The aqueous waste from the hydrogen plant could contain dissolved organics, inorganics (including trace metals), sulfur, and nitrogen compounds. It is assumed that an aqueous treatment system such as a multiple effect evaporator or vapor recompression evaporator would be used to further concentrate the wastes into a filtrable slurry and to recover water as condensate for reuse or discharge, perhaps with additional treatment required. The filter cake from the aqueous treatment system could be mixed with the soot and slag for landfill disposal.

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*The Fluor report assumes these high-TDS plant effluents are disposed of at a charge of $5/1000 gallons.

Miscellaneous aqueous wastes are also generated periodically and are handled by batch treatment (with aqueous portions discharged to the forebay of the storm basin).

Solid Waste Disposal--

The major solid wastes produced by the plant are soot (207.6 tpd) and slag (2543.5 tpd) from the hydrogen plant and derived from the coal feedstock. These materials are loaded into rail hopper cars for shipment offsite to a contractor-operated landfill under the supervision of the plant owner. The landfill site is a typical valley fill operation similar to those in the vicinity used for disposal of mine and coal preparation plant refuse. Over the life of the plant, some 18 million tons (dry) will be deposited.

Other plant solid wastes include lime-soda softener sludge, sludges from oil recovery operations, plant trash and garbage, and infrequent sludges resulting from equipment cleaning and basin cleanouts. It is assumed that items such as waste oils and scrap metals will be salvaged and that spent catalysts will be sent offsite for regeneration or disposal. These other solid wastes are dewatered where necessary and hauled by truck to the soot and slag landfill site for burial. The plant trash and garbage may be buried in a separate designated area of the fill site.

Plant Thermal Balance

The summary energy balance shown in Table 96 indicates an overall plant thermal efficiency of 67.7 percent (68.4 percent on an HHV basis). The Fluor report notes also that the Texaco package (H_2 plant) is conservative with respect to energy demands, especially steam (perhaps 50 percent less) and oxygen (8 to 10 percent less), so that the overall balance could be better than indicated. Addition of balance-of-plant modifications such as a water supply system and aqueous waste treatment facilities (high TDS waste concentration unit and sludge dewatering facilities) would consume some additional electrical power and perhaps steam, drawing down the improved balance somewhat.

Consumption and losses of 32.3 percent of input are represented principally be electric power consumption (and mechanical losses), steam power consumption (drivers), and heat rejected to the atmosphere by the process and power cooling systems and heat in hot flue gases from fired heaters.

The clean fuel products, naphtha (5.39 MM Btu/bbl) and fuel oil (6.5 MM Btu/bbl), represent 65.6 percent of the total energy input. Their properties are considerably different and their values as products could be considered economically different. The sulfur content in each product represents less than ten percent of that in the as-received coal on a pounds per million Btu basis. The heavy fuel oil could theoretically be burned in a power plant without an FGD system if the credit for fuel pretreatment were allowed. The naphtha product could also be used as a boiler fuel though it would probably be sold as a more valuable product.

TABLE 96. SUMMARY ENERGY BALANCE — H-COAL PROCESS

Element	MM Btu/hr	Percent of Total
Energy Input (LHV)		
Total Coal to Process	26,542	100.0
Energy Output (LHV)		
Products		
Naphtha	3,496	13.2
Fuel Oil	13,904	52.3
Product Subtotal	17,400	65.5
Byproducts		
Ammonia	121	0.4
Phenol	25	0.1
Sulfur	392	1.5
Electricity*	42	0.2
Subtotal (Products and Byproducts)	17,980	67.7
Consumption and Losses (Difference)	8,562	32.3
Total Energy Distribution	26,542	100.0

*Fuel Equivalent 10,000 Btu/kWh

COAL LIQUEFACTION PLANT COSTS

In the Fluor commercial evaluation report (7), construction costs were summarized by major process unit. That general format is retained here. Their mid-1975 equipment and labor costs were updated to first quarter 1978 (see Appendix C for details). Nonprocess modification costs, such as the addition of a water intake system and an effluent discharge system, were added to the updated costs.

The toal capital cost of $1.64 billion shown in Table 97 represents an investment of about $24,500/BPD of oil production. Specific pollution control costs were not identified in the Fluor report. Construction costs for the sulfur plant, sour water treatment, a small portion of coal preparation, a portion (ash handling) of the hydrogen plant, and a significant portion of offsites and utilities could be allocated as pollution control costs. These could total five to ten percent of the total construction sosts. Additional costs could be incurred if CO_2 vent gas were incinerated and if the sulfur recovery unit were to meet NSFS for SO_2 emission concentration of 0.025 percent in treated tail gas.

Annual operating and maintenance costs (Table 98) total $122.7 million or $5.50/bbl of naphtha and fuel oil output. Byproduct credits for sulfur, liquid ammonia, and mixed phenols reduce the annual operating expenses by $13.9 million or $0.62/bbl. Catalyst and chemicals, labor, and maintenance materials are large direct operating expenses, representing more than 60 percent of the total.

Allowances of $1.50/ton for solid waste disposal and $7.50/M gal for aqueous waste disposal were included as operating costs. If the major process residues from the plant were classified as hazardous materials, the cost for an environmentally secure landfill disposal might well be higher than $1.50/ton. It is also likely that the plant would need to install treatment systems for the aqueous waste effluent and for sludges from water and wastewater treatment. Charges for solid and aqueous waste systems would add several millions to the capital cost and could increase annual operating costs. A substantial increase in the cost of synthetic oil production would probably not occur from these changes.

The sensitivity of oil cost to the cost of coal is shown in Figure 39 for utility and private financing. Both the naphtha and the heavy fuel oil have been combined for simplicity. Oil production costs (zero coal cost) are about $13.70 and $20.40 per barrel, respectively. Assuming a $25 per ton base price for high sulfur coal, the oil costs are $24.50 and $30.88 per barrel. At current fuel oil prices of up to $2.50/MM Btu, these synthetic oil costs of about $3.90 and $4.90/MM Btu are not very competitive as a low-sulfur boiler fuel. The naphtha, of course, is a more valuable product than the heavy fuel oil. If separate pricing were considered, the relative heavy fuel oil cost would be less (see Fluor report, Ref. (7)).

TABLE 97. H-COAL CAPITAL COSTS

Element	$1,000,000's
Coal Preparation	74.0
Coal Hydrogenation	129.0
Product Recovery	64.0
Gas Processing	28.0
Sulfur Plant	19.0
Oxygen Plant	101.0
Hydrogen Plant	175.0
Sour Water Treatment	19.0
Product Storage and Loading	37.0
Offsite and Utilities	222.9
DIRECT FIELD COST	868.9
Indirect Field Cost	130.0
TOTAL FIELD COST	998.9
Engineering Services	120.0
	1,118.9
Allowance for Uncertainty	168.0
TOTAL CONSTRUCTION COST	1,286.9
Land	1.0
Other Owner Costs	23.7
Startup	47.3
Allowance for Funds During Construction	203.8
FIXED CAPITAL INVESTMENT	1,562.7
Working Capital	77.3
TOTAL CAPITAL COST First Quarter 1978, Price and Wage Levels	1,640.0

TABLE 98. ANNUAL OPERATING AND MAINTENANCE COSTS* — H-COAL

Element	$1,000,000's
Water	0.2
Catalyst and Chemicals	20.8
Operating and Maintenance Labor	17.5
Maintenance Materials	38.9
Supplies and Materials, Allowance	2.4
Insurance	9.6
Nonincome Tax	25.7
General Overhead and Administrative	4.0
Waste Disposal Allowance, Ash†	2.0
Waste Disposal Allowance, Aqueous Effluent**	1.6
TOTAL ANNUAL OPERATING COST	122.7
Byproduct Credits	13.9
NET ANNUAL OPERATING COST First Quarter 1978, Price and Wage Levels	108.8

*Excluding coal feedstock.
†$1.50/ton.
**$7.50/M gal.

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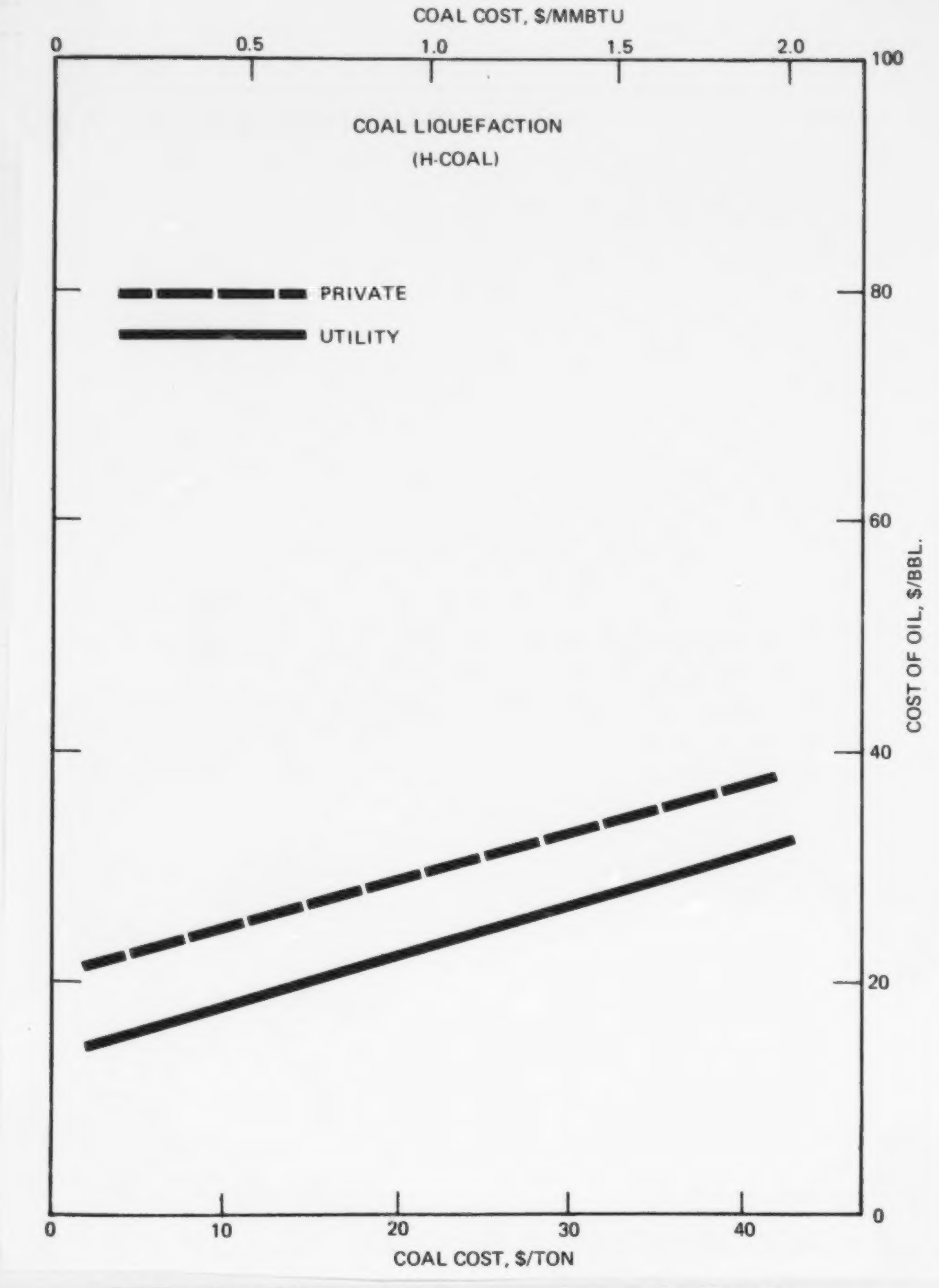

Figure 39. Effect of coal cost on cost of oil with both private and utility financing.

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COAL LIQUEFACTION ENVIRONMENTAL ASSESSMENT

Coal Procurement Impacts

About nine million tons of coal per year will be obtained from an existing underground mine complex in the eastern U.S. Underground mines have different impacts from surface mines since so little of the surface land area is involved.

Topography--
Construction of aboveground handling facilities will affect topography locally, but the major impact on topography will be the disposal of mine rock. Shallow valleys will be filled, altering the hilly character of the area and resulting in a more regular terrain with less surface relief.

Geology and Soils--
Mine rock has a potential for erosion and, in addition, will alter the surface characteristics of much land area. Other geological effects will include:

- Removal of the coal, a nonrenewable resource
- Potential subsidence of the area over the mine after abandonment

Groundwater--
Mine water from the two hypothetical mines will have to be removed, treated, and disposed of. This water is a low-quality groundwater which will not be committed to other regional uses. The third mine has good quality water which, while it can be used in the mining operation (dust control), does result in a reduction in local, and possibly regional, groundwater supplies.

Leaching from mine rock will have a small potential for contamination of groundwater, but this potential is dependent on the quality of the refuse.

Surface Water--
Disposal of acid mine water after treatment for iron and acidity reduction could add to present water quality problems in nearby drainage systems.

Air Quality--
Fugitive dust and gaseous emissions from the mine and from coal handling may locally degrade air quality. Dust control on mine faces, coal piles, and mine rock disposal, as well as the use of pollution controls on the conveyor discharge points, screens, and primary crushers, will reduce these emissions. Mine water may be used for this dust control, reducing discharges to surface water as well.

Vegetation--
Only a small acreage of agricultural or woodland vegetation will be affected by mine buildings, coal handling, or transport facilities. However, several hundred acres of shallow valleys will be filled with mine rock, eliminating riparian vegetation which is valuable wildlife habitat. While revegetation is contemplated, it is not likely that the same species mix would be reestablished and the value to wildlife would be reduced.

Wildlife--
A total regional reduction in species dependent on riparian woodlands will occur with ongoing mine rock disposal. This could have a particular impact on the bald eagle, an endangered species which usually nests near water in riparian woodlands.

Land Use--
Agricultural and woodland uses will be foreclosed in mine rock disposal areas. In addition, construction over the mined area may be restricted by the potential for subsidence.

Aesthetics--
Deep underground mines do not have the visual character typical of surface mines and tend not to have the aesthetic impact of surface mines. However, changes in topography and vegetation due to mine rock disposal will have an adverse aesthetic impact over a large area.

Social and Economic Effects--
The opening of three mines and the sale of more than nine million tons per year of coal (about $230 million at $25/ton) will result in more jobs, income, and no increases in population are likely.

Table 99 presents a brief summary of potential coal procurement impacts and mitigating measures.

Plant Impacts

Environmental impacts of the coal liquefaction project will result from plant construction and from operation of the plant over its 20-year life. The total construction period from start of engineering to completion of construction is assumed to be five years, and 3000 to 4000 workers will be on the site at the peak of construction. Construction activities will primarily result in short-term impacts on the physical environment, except for the permanent alteration of the land surface. Emissions from the operating plant may have longer-term adverse impacts on the physical and biological environment. Economic benefits will be derived from construction and operation. The plant will produce clean fuels and other byproducts for offsite consumption. The plant will consume resources as summarized in Tables 100 and 101. Additional resources — fuel, power, water, manpower, some chemicals, and all of the plant construction materials — will be used during plant construction.

This brief environmental assessment will focus on estimated impacts of the operating plant.

Physical/Chemical Emissions and Impacts--
Air, water, and solid waste emissions were estimated for the liquefaction plant based primarily on information contained in the Fluor report (7) and on Bechtel estimates where no information was available.

TABLE 99. PROCUREMENT IMPACT SUMMARY — COAL

Environmental Factors	Coal Mining Impacts	Mitigating Measures
Topography	Major local change due to mine rock disposal	
Soils and Geology	Potential for subsidence; change in surface character at mine rock disposal sites	
Groundwater Quality	Potential for disruption of flow by dewatering; leaching from mine rock disposal	
Surface Water	Degradation from runoff, erosion, mine water discharge	Revegetation of mine rock site; treatment of mine water
Air Quality	Fugitive dust	Dust control
Vegetation and Wildlife	Loss of large acreage of riparian habitat at mine rock disposal site	
Land Use	Change in use at mine rock disposal site	Revegetation
Aesthetics	Sharp visual effects at mine rock site	Revegetation
Community Economy	Potential for jobs, salaries, tax base	
Community Population and Services	No change expected	
Labor Availability	Sufficient labor pool	
Transportation	Mine site roads and railroads required	

TABLE 100. PRINCIPAL RESOURCES COMMITTED TO H-COAL PLANT OPERATION

Resource Category	Quantity	Normalized Quantity (Output)*
Land	440 acres	6.6 acres/MBPD**
Coal (11,900 Btu/lb)	9,277,740 tons/yr	133.3 lb/MM Btu
Auxiliary Fuel (Vehicles)	100,000 gal/yr	79 Btu/MM Btu
Auxiliary Power (Net Production)	(32 MM kWh/yr)	(+)
Water (9,092 gpm)	4,364 MM gal/yr	31.35 gal/MM Btu
Catalysts and Chemicals	37,950 tons/yr	0.545 lb/MM Btu
Manpower (726 Employees)	1.53 MM manhours/yr	0.011 manhours/MM Btu

*Basis: 139,200 trillion Btu/yr (LHV)
**Increases to 13.2 acres/MBPD if 440-acre buffer zone is included.

TABLE 101. ESTIMATED ANNUAL CATALYSTS AND CHEMICALS MAKEUP (7)

Material	Quantity
HDS-2A Catalyst	4,125 tons/yr
Bauxite Catalyst	13.2 tons/yr
Cobalt-Moly Catalyst	51.8 tons/yr
Shift Catalyst	85.1 tons/yr
n-decane, Antisolvent	24,244 tons/yr
Diglycolamine	22.4 tons/yr
Selexol Solvent	67.5 tons/yr
Lime (90% CaO)	3,505 tons/yr
Soda Ash (98%)	2,641 tons/yr
Sulfuric Acid (66° Be)	2,160 tons/yr
Caustic Soda (100%)	150 tons/yr
Biocide	50 tons/yr
Corrosion Inhibitor (Nonchromate)	60 tons/yr
Surfactant (Polymeric)	30 tons/yr
Scale and Sludge Control Agent (Dispersant)	118 tons/yr
Hydrazine (35%)	65 tons/yr
Morpholine	12 tons/yr
Disodium Phosphate (Anhydrous)	8 tons/yr
Trisodium Phosphate (Anhydrous)	10.4 tons/yr
Acetone	528.4 tons/yr
Dust Suppression Agent	3,000 gal/yr
Diesel and Gasoline Fuels	100,000 gal/yr

Air Emissions--The coal liquefaction plant will contain a significant number of point emission sources — from coal handling, from combustion units (process heaters and utility boilers), and from process vents. Table 102 presents estimates of air pollutant emissions from the plant, categorized principally as fugitive dust, sulfur compounds, nitrogen oxides, carbon monoxide, and hydrocarbons.

Coal handling will result in the release of fugitive emissions (coal dust) from both point and area sources. The quantities of dust emissions from the coal car dump hoppers, the coal stacker discharge, the bucket wheel reclaimer, and the storage piles will vary considerably and are difficult to estimate. Windblown dust emissions can be reduced by wet chemical suppression or enclosures at transfer points, sealing the dead storage pile, and periodic application of chemical dust suppressants on the live storage pile. Very rough estimates of fugitive dust releases in Table 102 indicate the potential for high local particulate concentrations in the air. Most of the heavier windblown dust particles will settle out in the vicinity of the release points, so that fugitive coal dust will not seriously degrade ambient air quality offsite.

Reclaimed coal will be ground in mills and dried using hot flue gases from three process gas-fired heaters. The dust-laden flue gas will pass through cyclone collectors and a wet scrubber before discharge to the atmosphere. The vented gas will contain some particulates plus small quantities of combustion product pollutants. Other process heaters, as well as the two power plant boilers, will also burn sulfur-free process gas, emitting small quantities of combustion product pollutants. Nitrogen oxide emissions are assumed to meet the proposed NSPS of 0.2 lb NO_2/MM Btu input for gas-fired steam-electric generators.

A small quantity of process vent gases will be incinerated in the flare systems. Sulfur dioxide is formed from combustion of sulfur compounds in vent gases. Hydrocarbons are converted to carbon dioxide and water.

The acid removal systems in the hydrogen plant will have carbon-dioxide-rich vent streams containing small quantities of hydrogen sulfide, carbon monoxide, hydrogen, and methane. Trace quantities of other non-methane organics will likely be present (possibly including toxic compounds). The large vent gas flows will result in significant pollutant releases on an annual basis, It is possible that incineration or scrubbing may be required as additional treatment for these vent gases.

The sulfur plant will convert more than 99 percent of the feed sulfur compounds into elemental sulfur. The tail gas, after cleanup, will contain about 1100 ppmv of sulfur oxides. Even though a large quantity of sulfur (over 1000 tons per day) will be removed from the sulfur-laden gases, the cleaned tail gas will still constitute a major sulfur oxide emission source of about nine tons per day. The SO_2 concentration estimated here exceeds the NSPS for sulfur recovery units in refineries. Additional tail gas sulfur removal could be required.

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TABLE 102. SUMMARY OF ESTIMATED AIR EMISSIONS — COAL TO OIL

Source	Flow Quantity	Pollutants	Emission Rate
Coal Car Dump Station	3,000 tph	Fugitive coal dust	1650 lb/day
(8 hoppers)	33,000 tpd avg	(0.05 lb/ton)	
(wet suppression)	(6 days/wk)		
Coal Pile Stacker	3,000 tph	Fugitive coal dust	1650 lb/day
Discharge(1)	33,000 tpd avg	(0.05 lb/ton)	
(wet suppression)	(6 days/week)		
Coal Reclaimer(1)	1,200 tph	Fugitive coal dust	1400 lb/day
(wet suppression)	27,836 tpd	(0.05 lb/ton)	
Dead Storage Pile,	1,670,000 tons	Fugitive coal dust	560 lb/day
60 days (sealed)	15 acres	(0.01 lb/ton/mo)	
Live Storage Piles,	83,500 tons	Fugitive coal dust	280 lb/day
3 days	6.5 acres	(0.1 lb/ton/mo)	
(wet suppression)			
Coal Surge Bins(3)	1,200 tph	Fugitive coal dust	130 lb/day
(bin vent collectors)	27,836 tpd		
Coal Dryer Flue	169,800 SCFM	Particulate matter	
Gases(3)	(486 MM Btu/hr	(0.08 gr/CF)*	116 lb/hr
(after cyclones and	input)	NO_x(0.2 lb/MM Btu)*	97 lb/hr
wet scrubbing)		CO(0.05 lb/MM Btu)*	24 lb/hr
		HC(0.02 lb/MM Btu)*	10 lb/hr
Process Heater	176,700 SCFM	NO_x(0.2 lb/MM Btu)*	166 lb/hr
Flue Gases(12)	(832 MM Btu/hr	CO(0.05 lb/MM Btu)*	42 lb/hr
	input)	HC(0.02 lb/MM Btu)*	17 lb/hr
Flare Gases,	422 SCFM	SO_x	50 lb/hr
H.P. and L.P. Flares		CO	trace lb/hr
		HC	trace lb/hr
Process Heater Flue	59,470 SCFM	NO_x(0.2 lb/MM Btu)*	56 lb/hr
Gases(6)	(280 MM Btu/hr	CO(0.05 lb/MM Btu)*	14 lb/hr
	input)	HC(0.02 lb/MM Btu)*	6 lb/hr
H_2 Plant CO_2	190,540 SCFM	H_2S	17 lb/hr
Vent Gases (2)		CO	312 lb/hr
		H_2	131 lb/hr
		CH_4	114 lb/hr
		COS and other organics	small amounts

(Continued)

TABLE 102. (Continued)

Source	Flow Quantity	Pollutants	Emission Rate
O_2 Plant Nitrogen Vent(3)	293,390 SCFM Nitrogen	None	-
Sulfur Plant Tail Gas(1)	66,660 SCFM (34 MM Btu/hr input)	SO_x NO_x(.2 lb/MM Btu)*	768 lb/hr 6.8 lb/hr
Power Plant Cooling Towers(2)	3,510,000 SCFM dry air, 1,560,000 lb/hr water vapor	Drift(water droplets) TDS (salts) Chemicals** Thermal	12,000 lb/hr 20.4 lb/hr 7.4 lb/hr 2,100 MM Btu/hr
Process Cooling Towers(2)	4,480,000 SCFM dry air 2,205,000 lb/hr water vapor	Drift (water droplets) TDS (salts) Chemicals** Thermal	15,000 lb/hr 150 lb/hr 10.8 lb/hr 2,678 MM/Btu/hr
Boiler Flue Gases(2)	574,560 SCFM (2705 MM/Btu hr input)	SO_x NO_x(0.2 lb/MM Btu)* CO(0.05 lb/MM Btu)* HC(0.02 lb/MM Btu)*	Small amount 541 lb/hr 135 lb/hr 54 lb/hr
Soot and Slag Car Loading	3,980 tons per day(wet)	Fugitive dust	Small amount
Hydrocarbon Storage and Transfer	1.9 MM bbl storage capacity, naphtha, fuel oil, mid-dist., solvent, phenols	Fugitive hydrocarbons	No estimate
Ammonia Storage And Transfer	46,000 cu ft capacity	Ammonia	No estimate

*Assumed emission factors.
**Water treatment chemicals in drift.

The oxygen plant nitrogen vents and the power plant and process cooling tower will be large volumetric rate emission sources — though relatively free of pollutants. Drift from the power plant cooling towers will carry out salts and chemicals added to the cooling water and possibly some ammonia hydrogen sulfide and residual phenols. These materials may also be stripped by the air/water contact and appear in the exhaust vapor. Drift from the process unit cooling towers will carry out about 150 lb/hr of dissolved solids, most of which will be deposited on the ground in the vicinity of the towers. There is also the potential of organics and ammonia in the circulating water being stripped into the exhaust air as well as being carried out in the drift.

The many pumps, valves, tanks, and vessels in the H-coal facility will be sources of fugitive hydrocarbon emission because of minor leakage, storage, and transfer losses. Total product storage capacity for the hydrocarbon liquids will be about 1.9 million barrels. Most of this tankage capacity is for heavy fuel oil, and vapor losses should be small. No estimates of fugitive hydrocarbon emissions or characteristics were made, however. The concern about emissions of potentially harmful compounds from synthetic fuel liquids should be noted.

Overall, the H-coal facility will emit a substantial tonnage per year of particulates, SO_2, NO_2, CO, and hydrocarbons. These emissions will result in a small degradation of ambient air quality in the vicinity of the plant. It is assumed that installation of this facility will not result in significant deterioration of regional air quality for designated pollutants other than photochemical oxidants. Emission offsets will probably be required as well as the use of best available control technology.

Wastewater Emissions--Table 103 lists major aqueous streams identified in the Fluor report (7). The water management scheme, as designed, includes internal treatment and recycling of streams to minimize the plant makeup water demand and to reduce the volume of aqueous effluent to be disposed of (assumed offsite disposal). Characteristics of internal recycle streams were not well defined. It is anticipated that the concentrated aqueous wastes (cooling tower blowdown, regenerant brines, and the H_2 plant waste) will contain a variety of inorganic and organic constituents. Water treating chemicals, residual pollutants from process effluents, and pollutant materials introduced from soot and slag handling will be present.

An onsite waste treatment system could be used to produce an effluent acceptable for discharge or reuse. A wastewater evaporator would concentrate nonvolatile inorganics and organics into slurry form for dewatering and offsite landfill disposal. Further cleanup of the condensate could be needed if ammonia or other volatile constituents were present in concentrations too high for discharge or for reuse in the plant. Upsets in internal treatment or recycle systems could also result in the temporary discharge to the river of untreated or partially treated wastewater. A short-term adverse effect on surface water quality could occur. The main storm basin will probably be used for impoundment of contaminated water during upset periods.

TABLE 103. SUMMARY OF ESTIMATED WASTEWATER EMISSIONS — COAL TO OIL

Source	Estimated Flow	Pollutants	Emission Rate
WWT Effluent (after treatment)	1810gpm (used as C.T. makeup)	Phenols (4mg/1) NH_3 (50 mg/1) H_2S (5 mg/1) pH	No direct emission
Granular Media Filter Backwash	75 gpm (intermittent) (softened for reuse)	TSS BOD	No direct emission
Micron Filter Backwash	37 gpm (intermittent) (softened for reuse)	TSS	No direct emission
Sanitary Wastewater (after treatment)	100 gpm (softened for reuse)	BOD(<20 mg/1) TSS(<20 mg/1) Coliforms pH	No direct emission
Utility Wastewater (after treatment)	200 gpm (softened for reuse)	Oil & Grease (<10 mg/1) TSS(<20 mg/1) pH	No direct emission
Contaminated Storm Runoff (after treatment)	60 gpm annual avg (softened for reuse)	Oil & Grease (<10 mg/1) TSS(<20 mg/1) pH	No direct emission
Boiler Blowdown	67 gpm (softened for reuse)	TDS* TSS pH	No direct emission
Coal Dryer Condensate (after treatment)	200 gpm (softened for reuse)	Oil & Grease (<10 mg/1) TSS(<20 mg/1) pH	No direct emission

(Continued)

TABLE 103. (Continued)

Source	Estimated Flow	Pollutants	Emission Rate
Power Plant C. T. Blowdown	495 gpm (softened for reuse)	NH_3 TDS**(1700 mg/l) TSS Phenols pH	No direct emission
Process C.T. Blowdown	202 gpm	TDS**(10,000 mg/l) TSS BOD pH	To aqueous waste disposal system
Ion Echange Regenerant Brines (after neutralization)	7 gpm avg. (intermittent)	TDS(up to 30,000 mg/l) TSS pH	To aqueous waste disposal system
Aqueous Waste from H_2 Plant (from soot and slag handling)	230 gpm	TDS TSS BOD NH_3, sulfides pH	To aqueous waste disposal system
Aqueous Waste Disposal Effluent (after treatment)†	429 gpm (To discharge or reuse)	BOD(<50 mg/l) NH_3(<50 mg/l) TDS(<20 mg/l) pH	<250 lb/day <250 lb/day <100 lb/day 6 to 9
Coal Yard Runoff (after settling)	65 gpm annual avg (intermittent)	Oil & Grease (<10 mg/l) TSS(<50 mg/l) ph	<8 lb/day <40 lb/day 6 to 9
Uncontaminated Storm Runoff (after settling)	350 gpm annual avg (intermittent)	Oil & Grease (<10 mg/l) TSS(<50 mg/l ph	<42 lb/day <210 lb/day 6 to 9

*Contains added chemicals - morpholine, hydrazine(decomposed), sodium phosphates, corrosion products.

**Contains added chemicals - sulfate, biocide, dispersant, corrosion inhibitor.

†Assumed onsite treatment system including evaporation.

Storm runoff in excess of that which can be impounded and reused will be discharged to the river. On an annual basis, the pollutant load contributed by discharged plant runoff will have a minor effect on the river water quality.

The normal aqueous discharge from the plant should have little effect on the river water quality outside of the mixing zone. The flow rate will be relatively low and, with proper wastewater treatment, the pollutant load will be low. The plant consumption of about 9100 gpm will be only about 0.25 percent of the average river flow, so that a significant impact on surface water availability is not expected.

Solid Waste Emissions--Table 104 lists approximate quantities of solid wastes that will be produced by the operating plant. Nearly all of the unreacted coal constituents from liquefaction will be converted to synthesis gas and soot and slag wastes in the hydrogen plant. The hydrogen plant will contain solids thickening and dewatering facilities to prepare the soot and slag for loading into rail hopper cars and offsite disposal.

The soot will be nearly all carbon and some 69,200 tons per year (dry basis) will be produced. This waste material is assumed to be in the form of wet finely divided particulates with about 40 percent surface moisture as prepared for disposal. Slag from the Texaco gasifiers will be discharged in slurry form and dewatered. The material is assumed to be primarily the inorganic portion of the raw coal (ash). About 847,800 tons per year (dry basis) will be transported offsite for disposal. Its physical characteristics should be similar to those of boiler bottom ash (slag). The wet slag is assumed to contain 30 percent moisture as loaded into rail cars.

Water treatment wastes will include dewatered sludge (42 tons per day) from lime-soda softening of cooling tower blowdown and dewatered brine slurry (65 tons per day) from an onsite aqueous waste treatment system. Both wastes will be produced from efforts to minimize aqueous pollutant discharges.

Plant trash and garbage will be another solid waste routinely produced during plant operation. It is assumed that salvageable spent catalysts, lube oils, and scrap metals will be sent offsite for recovery, if practical. Nonsalvageable materials will be hauled offsite for burial. Miscellaneous wastes also will result from cleanouts during maintenance or turnaround operations. These infrequently produced sludges and solids will presumably be disposed of offsite in a landfill after adequate onsite treatment.

The offsite solid waste disposal area is assumed environmentally suitable for all of the plant's wastes over its 20-year operating life (on the order of 27 million tons). In this particular region, the landfill disposal site will be operated somewhat like a coal refuse disposal site. The plant's other solid wastes will also be buried, and special handling could be needed to ensure proper disposal, such as designated disposal sites for particular types of wastes and special precautions to prevent contact with surface and groundwater. With proper selection of the disposal area and good disposal practices, surface and groundwater resources can be adequately protected. At the disposal site, provision for collection and treatment of any leachate or contaminated surface

TABLE 104. SOLID WASTE DISPOSAL SUMMARY – COAL TO OIL

Source	Estimated Quantity	Potential Pollutants	Disposal
Soot from H_2 Plant	207.6 tpd solids 138.4 tpd water	Carbon, organics, suspendable solids	Hauled by rail to valley landfill - spread, compacted, and covered
Slag from H_2 Plant	2,543.5 tpd solids 1,090 tpd water	Minerals, trace elements and organics	Hauled by rail to valley landfill - spread, compacted, and covered
Lime-soda Softener Sludge Filter Cake	8.4 tpd solids 33.6 tpd water	Inorganics, organics, NH_3, chemical additives, corrosion products	Dewatered and hauled to offsite landfill
Filter Cake from Aqueous Waste Treatment	26 tpd solids 39 tpd water	Inorganics, organics, heavy metals, suspendable solids	Dewatered and hauled to offsite landfill
Plant Trash and Garbage	1,700 lb/day	Decomposable wastes, some oily materials	Collected twice per week, compacted and buried in offsite landfill
Spent Catalysts (HDS, Bauxite, CO-Mo, Shift Catalysts)	4,275 tpd (average)	Heavy metals, residual organics	Returned for regeneration/disposal or buried in offsite landfill
Miscellaneous: Oil Recovery Sludges Equipment Cleanout Sludges Basin Cleanout Sludges	No estimates made of quantities	Organics, inorganics, suspendable solids	Dewatered and buried in offsite landfill

runoff will need to be made. A low permeability base material such as clay could retard movement of contaminants into any groundwater resources.

There is a potential that the soot and slag residues, more than 95 percent of the total waste, may be classified as hazardous materials rather than coal refuse-type materials commonly disposed of in this area. A substantially more complex and expensive disposal operation could be required.

Soils and Geology--Approximately 440 acres of land will be altered by construction activities (clearing, grading, cut-and-fill excavation, paving) and additional offsite lands will be affected by the building of access roads, rail spurs, and pipelines. During operation, the disposal of plant solid wastes in shallow valleys will alter topography by raising the height of the disposal sites over time, reducing the hilly character of the area. This change will be significant to regional topography.

Biological Effects--

Four hundred and forty acres of farmland and woodland will be cleared during construction. While this acreage is not significant in a regional sense, the impact will depend on the actual amount of wooded land disturbed. In an area such as this hypothetical eastern site, which has been converted extensively to agricultural or industrial use, little natural habitat remains. In this type of situation, removal of even a small acreage of natural habitat could be significant to regional ecology. Care in siting of the facility will minimize this potentially adverse impact.

Secondary impacts include effects of degraded air quality and water quality:

- Increased exposure to SO_x and particulates, with loss of some sensitive plants possible

- Increased salt concentrations in soil downwind from the cooling tower, decreasing soil productivity locally

- Local minor degradation of aquatic habitat due to plant aqueous discharge; aggravated if the water supply is currently affected by acid mine drainage or other industrial effluents

- Potential icing and resultant vegetation damage if cooling tower plumes increase chances of freezing rain

Operation of water intake systems can result in entrainment of smaller species and impingement of fishes on protective screens. The entrained species will be killed, but design and location of the intake will minimize entrainment effects.

Aesthetic Impacts--

The presence of the H-coal facility on previously agricultural and wooded land constitutes a change in the visual character of the area and a possible adverse impact. Building structures, coal piles, and transportation facilities constitute the major sources of visual contrast in texture, shape, and color.

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While industrial use is not uncommon in the area, conversion of a less disturbed area to new industrial use could in itself be an impact since the relief offered by the presence of greenbelts or open spaces would be exchanged for the more urban character.

Layout of the plant to reduce visibility of structures from nearby roads or residential areas is a potential mitigating measure. This could include setting the structures well back from the highway, utilizing a 440-acre buffer zone, placing administrative buildings between roadways and reactor trains, and using trees as visual screens.

Social and Economic Effects--
A portion of the capital investment ($1.6 billion) will be spent locally for equipment, construction materials, and labor. The jobs created for 3000 to 4000 temporary construction workers and for 726 permanent operations staff will result in wages and salaries being infused into the regional economy. The plant will also expand the tax base for local or state use and may offset increased demands for services.

Manpower will probably be available in this more industrialized region, particularly people trained in the coal industry. Local training programs may be used to supplement the labor pool of skilled construction and operating workers.

The plant will consume auxiliary fuel and power, but this consumption will be outweighed by the fuel produced. Coal, a nonrenewable resource, will be consumed.

Table 105 summarizes the anticipated impacts of the H-coal facility in this hypothetical location.

TABLE 105. SUMMARY ENVIRONMENTAL MATRIX — H-COAL

Environmental Factors	Effect of Plant Construction and Operation	Potential Mitigating Measures
Climatology and Meteorology	Potential for fogging from cooling tower during periods of high humidity	
Air Quality	Fugitive dust and vehicle emissions during construction; fugitive dust (coal), some particulates, HC, CO; moderate to significant emissions of H_2S, SO_x; cooling tower drift and salt releases	Dust suppression, use of low sulfur fuel for combustion, pollution control (scrubbers, etc.)
Surface Water Availability	31 gal/MM Btu consumed	Internal recycling
Surface Water Quality	Releases of sediment during construction; TDS, TSS, BOD released from waste streams — local discharge effect small (but potentially important in presently polluted system)	Construction techniques to prevent erosion; internal recycling to reduce pollutant discharges
Groundwater Availability	No consumption — no effect	
Groundwater Quality	Potential degradation from leaching of coal piles, landfill and wasteponds	Lined ponds; careful management of landfill, pads or silos for coal storage
Land Availability	880 acres used — insignificant regional effect. Solid waste acreage potentially significant	Care in siting for compatibility, value of land use
Regional Ecology and Critical Habitat	440 acres of vegetation and wildlife removed or disturbed; salt drift and/or dust effects on plants, human activity disturbing wildlife and water quality degradation stressing aquatic life. Solid waste disposal acreage disturbed — potentially significant impact	Care in siting; water recycling to minimize consumption and degradation

(Continued)

TABLE 105. (Continued)

Environmental Factors	Effect of Plant Construction and Operation	Potential Mitigating Measures
Aesthetic Resources	Massive structures, coal piles, change in land use result in significant visual contrast	Landscaping, plant layout
Historical, Archaeological Resources	No significant effects	Care in siting
Community Economy	Potential benefit from capital expenditures, jobs, tax base	
Community Population and Services	Minimum impact	
Labor Availability	Sufficient labor pool	Training if needed
Power Availability	34 MM kWh/yr net production	
Transportation Availability	Access road, rail spurs, pipelines	Care in siting

SECTION 6

ECONOMIC AND ENVIRONMENTAL COMPARISONS

Sections 3, 4, and 5 presented details of each of the six conversion cases, paired by product and region. Each of the three biomass and coal pairs are compared here, first on an economic and then on an environmental-impact basis.

WOOD AND COAL TO ELECTRIC POWER

The 50 MWe and 500 MWe plants would produce electric power from wood residue and coal in the South Central scenario.

Economic Comparison of Power Production — Scenario 1

As of today, one cannot expect that wood conversion to electric power can compete economically with large coal-fired electric generating stations. There is no advantage of conversion efficiency for wood fuels in direct combustion-steam electric generation. Coal conversion penalties could be coal costs, capital and operating costs, or environmental costs (affecting the preceding costs). Table 106 is a summation of pertinent economic factors for the two plants. A tenfold capacity difference favors the coal-fired plant because of economy of scale.

In most of the comparison categories, the wood-fired plant suffers a considerable deficit, stemming primarily from the substantial differences in plant capacity and conversion efficiency. Capital cost, annual operating cost, and hence base production cost are all about 50 to 60 percent higher for the wood case based on output. For comparable capacity plants (50 MWe), these factors would be much closer. The wood-fired plant could be more attractive than a 500 MWe coal-fired plant with an FGD system. However, new coal-fired stations of less than 100 MWe are not likely to be constructed in the south central region.

The base production cost of electricity (excluding fuel cost) for the wood-fired plant is 28.5 mills/kWh versus 19 mills/kWh for the coal-fired plant. With private financing, these costs are considerably higher in both cases. If wood were available at a very low price, the cost of electricity would be nearly competitive with electricity from a large coal-fired plant. Table 106 gives costs of electricity with wood at $10 per ton and coal at $25 per ton as example fuel costs for this scenario. For utility financing, the 45.8 mills/kWh wood-to-power cost is 60 percent higher than the base production cost and about 60 percent higher than the corresponding coal-to-power cost.

TABLE 106. ECONOMIC COMPARISON OF WOOD AND COAL TO POWER

Element	Wood to Power (45 MWe)	Coal to Power (476 MWe)
Feedstock Input, MM Btu/yr	4,357,000	27,857,000
Power Output, MM kWh/yr	275.9	2,913
Thermal Efficiency, %	21.6	35.1
Capital Cost		
$ Million	54.2	384
$/kW (Net)	1,202	807
Operating Cost*		
$ Million/yr	2.2	14.8
Mills/kWh (Net)	8.0	5.1
Base Production Cost*		
Utility, Mills/kWh (Net)	28.5	19.0
Private, Mills/kWh (Net)	45.5	32.0
Example Cost of Electricity**		
Utility, Mills/kWh (Net)	45.8	28.2
Private, Mills/kWh (Net)	62.8	41.2

* Excludes feedstock cost.
** Includes wood residue at $10/ton ($1.10/MM Btu) and coal at $25/ton ($0.96/MM Btu).

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Figure 40 further illustrates the importance of the wood cost with respect to the cost of electricity; namely, high costs for delivered wood will make the electricity costs very unattractive compared with costs of electricity from new large coal-fired stations with FGD systems.

Despite these economic disadvantages, a small wood-fired power station could be attractive in a scenario where wood is available at a low cost and there is no demand for a large electric-generating station in the area. Co-firing of wood and coal may also be economic where coal prices are high enough to offset retrofit costs.

Environmental Comparison — Scenario 1

Feedstock Procurement--

The primary sources of environmental impact in feedstock procurement are the actual physical activities of gathering and removing wood residue or coal. These activities may directly affect soils, geology, topography, and land use and indirectly affect water quality and soil productivity. The following paragraphs compare the effects of feedstock procurement for the wood-to-power and coal-to-power plants, and these effects are summarized in Table 107.

Air Quality--Short-term increases in particulate concentrations (resulting from fugitive dust) are expected from both feedstock procurement activities. The actual quantities of fugitive dust will depend on the acreage exposed to wind action; wood refuse collection, properly managed, will probably result in lower windborne particulates than surface mining. However, the total surface area exposed in both instances will be small, regionally, and neither activity should contribute significantly to the regional pollutant loading.

Surface Water--Wood residue procurement may result in increased sediment loads to streams in the region since some unstable soils may be exposed and subject to erosion. Careful management of residue collection, particularly in drainage areas known to be susceptible to erosion, will minimize this effect. No impact on water availability is expected.

Coal procurement, on the other hand, may affect water quality and water availability. In addition to sediment loading in streams as a result of exposing subsoils and stockpiling topsoil for revegetation and reclamation, some water quality degradation may result from acid mine drainage. This degradation can be controlled by using state-of-the-art reclamation procedures, but any acid mine drainage could have potentially long-term adverse impacts downstream of the mine.

Surface water availability could be affected during mining since drainage systems will be affected directly. By the removal of surface materials, the natural drainage will be altered, and some stream beds may even be removed or channelized. In addition, the use of cofferdams and other erosion control measures to limit the impact on water quality will reduce downstream flows. These effects should be short-term and should cease upon reclamation and restoration of the natural topography.

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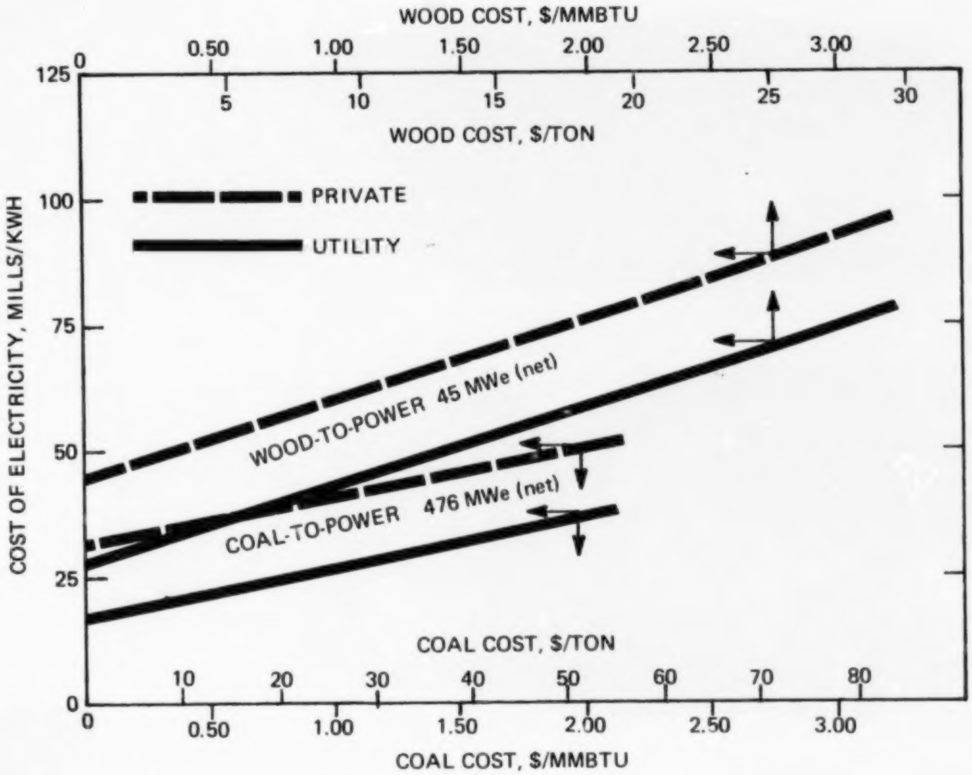

Figure 40. Effect of feedstock cost on the cost of electricity.

TABLE 107. IMPACT SUMMARY FOR SITE SPECIFIC FACTORS — FEEDSTOCK PROCUREMENT

Site Specific Factors	No Discernible Impact	Beneficial Impact	Adverse Impact (a)	Short Term	Long Term	Direct	Indirect	Mitigating Measures (b)
FOREST RESIDUE PROCUREMENT SOUTH CENTRAL U.S.								
Climatology and Meteorology	X							
Air Quality			I	X		X		
Surface Water Availability	X							
Surface Water Quality			I	X		X		A
Groundwater Availability	X							
Groundwater Quality	X							
Soils and Geology			I-M		X		X	A
Land Availability			I	X		X		A
Regional Ecology and Critical Habitats		X						A
Aesthetic Resources		X						
Historical, Archaeological Resources	X							
Community Economy		$X^{(d)}$						
Community Population and Services	X							
Labor Availability		X						
Power Availability	X							
Transportation Availability			I		X	X		
COAL PROCUREMENT, SOUTH CENTRAL U.S.								
Climatology and Meteorology	X							
Air Quality			I	X		X		
Surface Water Availability			I	X		X		
Surface Water Quality			I		X	X		A
Groundwater Availability			I-M		X	X		
Groundwater Quality			I-M		X	X		
Soils and Geology			M-S		X	X		
Land Availability			I	X		X		A
Regional Ecology and Critical Habitats			I-M		X	X		A
Aesthetic Resources			M		X	X		A
Historical, Archaeological Resources			I-M		X	X		A
Community Economy		$X^{(d)}$						
Community Population and Services			I		X	X		
Labor Availability			I	X		X		A
Power Availability	X							
Transportation Availability			I		X	X		

(a) Key for symbols used in adverse impact ratings:
S = Potentially significant
M = Moderate
I = Potentially insignificant

(b) Key for symbols used in mitigating measures ratings:
A = Mitigating measures described in text assumed to be implemented

(c) Assumes no other large scale development in the area coincident with power plant development or synthetic fuel.

(d) Assumes cooperation between plant and government agencies to promote reasonable, economically sound growth.

(e) Assumes power production or fuel production is a benefit to the community outweighing minor power consumption during construction or during operation.

Groundwater--Wood residue procurement should have no impact on groundwater supplies. However, coal procurement could affect long-term availability and quality of groundwater. The magnitude of the impact depends on the aquifers in the region of the mine, their location, recharge and discharge areas, and quality.

The quantity of groundwater could be affected by interrupting recharge areas during mining; the alterations to recharge areas could persist after reclamation, since stratigraphy and the physical interaction of soil/subsoil horizons will be permanently altered. Discharge of groundwater could be significantly affected, at least on the short term, if dewatering were necessary in the mine pit. In this instance, quantities of groundwater could be pumped out upstream of the discharge area, depleting the aquifer downstream. In addition, shallow aquifers could be cut (if above the coal seam) or removed (if in the coal seam horizon), resulting in an interruption of flow to the discharge area downstream. Depending on the regional use of water from these aquifers, potential long-term adverse impacts on groundwater availability could result.

Groundwater quality could be altered by surface mining activities. In addition to affecting recharge rates and locations, changes in stratigraphy could affect the chemical composition of the water by altering the sources of chemicals and their proportions (rock and soil composition may be affected). Also, changes in stratigraphy which resulted in the cutting of more than one shallow aquifier could result in mixing of groundwater supplies. If one aquifer were of lesser quality, it could significantly affect the quality, and therefore the usefulness, of others.

Soils and Geology--Both wood residue and coal procurement can adversely affect soils productivity, and mitigation of this impact requires extensive use of fertilizers and soil conditioners after procurement. Wood residue contributes to the organic content of forest soils; removal of a portion of this residue limits this contribution and, in time, contributes to decreased productivity. Forestry practice would probably have to include the addition of expensive fertilizers and soil conditioners to maintain yields at present levels.

Coal procurement involves removal of topsoils which, when stockpiled for use in reclamation, may be lowered in productivity. For example, richer topsoils may be mixed with less fertile subsoils. Organic materials which normally contribute to organic content are usually removed, and then natural soil bacteria and fungi may die, resulting in sterile soil after long periods of stockpiling. Upon reclamation, fertilizers and soil conditioners must be applied before planting to ensure yields. In some instances, subsoils may contain minerals or salts toxic to plant growth, but normally they are below the root zone. In reclamation, some of these undesirable materials may be brought to the surface, further reducing productivity. Special soil separation techniques may be necessary to prevent this type of problem.

Both wood and coal procurement increase the potential for erosion and loss of valuable topsoil. In addition, coal procurement alters soil and geology structure by altering soil horizons and stratification of beds, resulting in "bulking" of the overburden with potential for settling after reclamation, and changing topography. On a long-term basis, the overall impact on geology and soils is potentially greater from coal surface mining because of the extent of surface disruption, the depth disturbed, and the physical changes which occur.

Land Availability--Wood residue collection will require between 30,000 and 100,000 acres per year; acreage committed to coal mining will depend on the richness of the deposit and the surface area necessary to obtain one million tons per year. Wood residue removal does not foreclose any other land use, although the acreage used in any given year will not be suitable for wood residue collection for a long period after removal. Similarly, after coal mining and reclamation, no other land use will be prohibited although coal mining will be permanently foreclosed. Therefore, given adequate wood and coal resources, feedstock procurement should not have a significant impact on land availability.

Ecology--Removal of forest residue may disturb or eliminate wildlife habitat in up to 100,000 acres a year. Repopulation of the cleared area will depend on rate of accumulation of forest floor debris as well as regrowth of any cut-over stands of trees. Total acreage disturbed over the life of the project may be significant. However, the disturbance itself will be minor and could be beneficial if residue collection is coordinated with fire management in the region. For example, pine flatwoods are a "fire climax" ecosystem; hardwoods such as oaks and underbrush invade if occasional fires do not occur. When hardwood and underbrush do occur, any fire may have serious wide-ranging impact on the environment, since the normally resistant pines cannot survive the heat of a fire fueled by all that residue. Keeping the forest floor cleared and controlled use of fire can maintain a healthy pinewood against this potential fire danger (42, 43).

Coal mining will remove an undefined number of acres of wildlife habitat per year. Reclamation and revegetation may, if pursued immediately upon completion of mining in an area, minimize the overall adverse impact of removal by reestablishing wildlife habitat. However, if the mine is located in a mature pine flatwoods ecosystem, the wildlife typical of that system cannot return until a mature pine flatwood is reestablished. This could take between 25 and 100 years (43) and could be particularly significant to populations of species dependent on mature pinewoods, such as the endangered red cockaded woodpecker. Over the life of the mine, a significant acreage of woodpecker habitat could be removed in this region.

Aesthetics--The open park-like appearance resulting from wood residue collection in a pine woods could enhance the aesthetic appeal of the woods, if careful management of the collection prevented erosion, displacement of wildlife, and damage to mature vegetation. However, the contrasts in color, line, and texture resulting from surface mining of coal are adverse impacts on aesthetics. Reclamation will reduce this effect over time, but, for the life of the mine, the area will be adversely affected.

Historic and Archaeological Resources--Wood residue collection should not affect any historic ar archaeological resources. Coal surface mining could uncover such resources, and care in locating, retrieving, and protecting subsurface artifacts would be required. Mining might be prohibited in an area designated as a historic landmark.

Social and Economic Effects--Approximately 30 to 50 full-time jobs, associated wages and spending, and several million dollars per year paid for wood residue will benefit the community. No adverse effects on population, services, or power consumption are anticipated.

Coal mining will provide full-time employment, wages, and money paid for the coal ($20 to 25 million per year) to the community. However, if the mine is in a previously undeveloped area, labor may need to be imported, labor training programs may need to be implemented, and expanded services and housing may be required. These requirements are expected to produce insignificant impacts on a regional basis, but could produce moderate impacts on local communities.

Conversion Plants--
Air, water, and solid waste emissions are the major sources of environmental impact from wood-to-power and coal-to-power plants. These emissions directly affect physical and chemical aspects of the environment (air quality, surface and groundwater quality) and indirectly affect biological and aesthetic resources. Section 3 discussed the typical pollutants and expected levels of emissions with respect to site quality and environmental standards. The following paragraphs compare the two facilities with respect to these emissions and their potential effects on the environment. The impacts are summarized in Table 108.

Climatology and Meteorology--Both wood-burning and coal-burning power plants are assumed to use cooling towers which will release heat and water vapor to the atmosphere. The wood-burning plant cooling towers will release 250,000 lb/hr of water vapor, while the coal-fired plant will release about 1,750,000 lb/hr. Both could cause local fogging on cool, humid days, with the coal-fired plant having the greater potential. On a MWe basis, the wood-burning plant (50 MWe) releases more water vapor than the coal-fired plant (500 MWe). Similar impacts are expected from plants of similar sizes, regardless of feedtsock.

Air Quality--Low nitrogen and sulfur content in the wood residue will result in low emissions of NO_x and SO_x from the wood-burning plant. New source particulate standards could be met by using mechanical collectors and electrostatic precipitators. However, an estimated 1000 tons/year of NO_x, 200 tons/year of CO, and 200 tons/year of HC will constitute major new source emissions, and some measurable adverse effects could occur. In addition, 15 tons/year of salts will be distributed downwind of the cooling tower.

The coal-fired power plant is expected to meet NSPS particulate, NO_x, and SO_x standards. However, the total emissions from the plant may be as much as 11,700 tons/year of NO_x, 4400 tons/year of SO_x, 1000 tons/year of CO, and 400 tons/year of HC, as well as trace amounts of volatile materials. On a MWe basis, these emissions are less than or equivalent to wood-burning emissions with the exception of SO_x and the trace volatile materials. About 120 tons per day of salts will also be distributed downwind from cooling

TABLE 108. IMPACT SUMMARY FOR SITE SPECIFIC FACTORS — WOOD AND COAL TO POWER

Site Specific Factors	No Discernible Impact	Beneficial Impact	Adverse Impact (a)	Short Term	Long Term	Direct	Indirect	Mitigating Measures (b)
WOOD-TO-POWER, 50 MWe WOOD-FIRED POWER PLANT, SOUTH CENTRAL U.S.								
Climatology and Meteorology			I	X		X		
Air Quality			I(c)		X	X		A
Surface Water Availability			I	X		X		
Surface Water Quality			I	X		X		A
Groundwater Availability	X							
Groundwater Quality			I		X		X	A
Soils and Geology			I		X		X	
Land Availability			I(c)		X	X		A
Regional Ecology and Critical Habitats			I		X	X		A
Aesthetic Resources			I-M		X	X		A
Historical, Archaeological Resources			I		X	X		A
Community Economy		X(d)						
Community Population and Services			I	X		X		
Labor Availability			I	X		X		A
Power Availability		X(e)						
Transportation Availability			I		X	X		A
COAL-TO-POWER, 500 MWe COAL-FIRED POWER PLANT, SOUTH CENTRAL U.S.								
Climatology and Meteorology			I	X		X		
Air Quality			I(c)		X	X		A
Surface Water Availability			I	X		X		
Surface Water Quality			I	X		X		A
Groundwater Availability	X							
Groundwater Quality			I		X		X	A
Soils and Geology			M		X		X	
Land Availability			I(c)		X	X		A
Regional Ecology and Critical Habitats			I		X	X		A
Aesthetic Resources			M		X	X		A
Historical, Archaeological Resources			I		X	X		A
Community Economy		X(d)						
Community Population and Services			I-M	X		X		A
Labor Availability			I	X		X		A
Power Availability		X(e)						
Transportation Availability			I		X	X		A

(a) Key for symbols used in adverse impact ratings:
S = Potentially significant
M = Moderate
I = Potentially insignificant

(b) Key for symbols used in mitigating measures ratings:
A = Mitigating measures described in text assumed to be implemented

(c) Assumes no other large scale development in the area coincident with power plant development or synthetic fuel.

(d) Assumes cooperation between plant and government agencies to promote reasonable, economically sound growth.

(e) Assumes power production or fuel production is a benefit to the community outweighing minor power consumption during construction or during operation.

towers, roughly equivalent to salts from the wood-burning plant on a MWe basis. Some local adverse effects on air quality are expected, although, as with wood-burning plants, the significance of the effect will depend on ambient air quality and the existence of other point sources in the region. For example, the plant site is in a nonattainment area for photochemical oxidants, and emission offsets may be required for both plants.

Surface Water--The wood-burning plant will require about 0.8 gal/kWh for boiler feed and cooling water makeup, while the coal-fired plant will require about 0.5 gal/kWh. Neither should significantly affect surface water supply availability.

Discharges from the wood-burning plant include TDS, TSS, residual chlorine, small amounts of oil and grease, BOD, and coliform bacteria. The quantities discharged (about 100 gpm) and the concentrations of material in the effluent are not expected to significantly degrade water quality.

The coal-fired plant will discharge larger quantities of effluent of similar quality. Runoff from plant-site coal piles and sludge landfills could pose a problem to surface waters, but proper management of landfills and use of sedimentation basins for plant-site runoff will reduce this effect.

Groundwater--Neither facility is expected to use groundwater as a makeup or potable supply. However, both could affect groundwater quality through leachates from ash and sludge disposal sites. The composition of such leachates is not known, but any change in groundwater quality is long-term and possible cumulative, so particular care in landfill disposal of solid wastes will be necessary to minimize this potential adverse impact.

Soils and Geology--About 50 acres of surface will be altered for the wood-burning plant and about 365 for the coal-fired plant. Although these are roughly proportional on a per-MWe basis, coal plant acreage is not linearly related to energy generated. Similarly, about five acres will be committed to a landfill for solid waste disposal for the wood-burning plant and 230 acres for the coal-fired plant. Either plant may result in locally significant impacts on topsoil and topography. This alteration may or may not be regionally significant, depending on other changes to regional topography and other developments.

Land Availability--Commitment of 50 acres to a wood-burning plant and 365 acres to a coal-fired plant should not constitute a constraint on land availability. The use of buffer zones, say, 365 acres for the coal-fired plant, might be a problem in land acquisition; but agricultural, grazing, or forestry land uses would be compatible with use as a buffer zone. Therefore, depending on siting and on planned development in the area, land availability should not be significantly affected.

Ecology--Approximately 50 acres of wildlife habitat will be removed or disturbed during construction of a wood-burning power plant. Care in siting could minimize the regional effect of this loss by avoidance of critical habitats, known nesting or feeding areas of important species, or other ecologically sensitive areas. Similarly, the 365 acres disturbed by construction of a coal-fired power plant can be minimized by care in siting.

Impacts on vegetation and wildlife resulting from degradation of air or water quality will be similar for each facility, although losses due to salt deposition on vegetation from cooling-tower drift may be greater for the coal-fired plant.

Aesthetics--Both facilities will impose an industrial character on their sites; the magnitude of impact will essentially be proportional to the magnitude of the facility. Color contrast from coal piles and landfills will be greater for the coal-fired plant than for the wood-burning facility, and because of the required acreage, the coal-fired plant will constitute a greater impact on aesthetics than the wood-burning plant. However, landscaping, plant layout, and the use of the buffer zone can reduce the local impact of the plant itself.

Historic and Archaeological Resources--Care in siting will reduce the impact on historical or archaeological resources, as will salvage and protection should any subsurface relics be discovered.

Social and Economic Effects--Approximately 200 to 300 construction jobs and 300 full-time operational positions will be created by the 50 MWe wood-burning plant. The coal-fired plant will require a larger labor pool both for construction (up to 1000) and for plant operation (95 employees). Therefore, both will benefit the community in employment, wages, and local spending. Per MWe, these benefits are likely to be equivalent, and demands for services, housing, and labor training are expected to be equivalent. However, the coal-fired plant, as a larger unit, has a potentially greater effect on local growth.

Both plants will produce electric power for the region. The coal-fired plant, being more efficient, will produce more energy per ton of feedstock and will produce cheaper electricity. The costs of feedstock do not generally take into account that wood residue, over time, is renewable, while coal is a nonrenewable fuel source.

Consumption of Resources--Table 109 shows the natural resource consumption rates expected from each plant. The two facilities consume roughly equivalent quantities with three notable exceptions:

- The wood-burning plant, using a lower-Btu fuel, consumes more feedstock (lb/kWh) of a renewable resource, while the coal-fired plant consumes lesser quantities of a higher-Btu, nonrenewable fuel

- The coal-burning plant consumes more chemicals (particularly lime) in total than the wood-burning plant

- The coal-fired plant requires less manpower per kWh of output (due more to economy of scale than to superior conversion efficiency)

Summary of Scenario 1--
If the qualitative assessments summarized in Tables 107 and 108 were assigned numerical values using the scale shown in Table 110 and summed without

TABLE 109. RESOURCES COMMITTED TO THE POWER PLANTS*

Resource	Wood to Power 50 MWe	Coal to Power 500 MWe
Land	1.11 acre/MWe	0.77 acre/MWe**
Feedstock	3.46 lb/kWh	0.734 lb/kWh
Auxiliary Fuels	188 Btu/kWh	169 Btu/kWh
Chemicals	0.00046 lb/kWh	0.022 lb/kWh
Auxiliary Power	0.109 kW/kW	0.06 kW/kW
Water	0.82 gal/kWh	0.51 gal/kWh
Manpower	0.67 men/MWe	0.2 men/MWe

*From Tables 25 and 38.
**Increases to 1.54 if a 365 acre buffer zone is included.

weighting environmental aspects according to value to the site and region, feedstock procurement for coal-fired plants would potentially have significantly higher impact than wood-residue collection (Table 111). The regional impacts of the two power plants, on a MWe (relative) basis, however, would be similar. The biomass conversion facility would be more environmentally acceptable in this scenario largely because of the lower overall impact of feedstock procurement (forest residue) compared with coal mining.

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TABLE 110. SAMPLE NUMERICAL RATINGS FOR QUALITATIVE ASSESSMENTS

Scale	Environmental Qualitative Assessment
+10	Significant benefit
9	
8	
7	
6	
5	Moderate benefit
4	
3	
2	
+1	Insignificant benefit
0	No discernible impact
-1	Insignificant adverse short-term impact
2	
3	Moderate adverse short-term impact
4	
5	Significant adverse short-term impact
6	Insignificant adverse long-term impact
7	
8	Moderate adverse long-term impact
9	
-10	Significant adverse long-term impact

TABLE 111. SUMMARY OF WOOD AND COAL TO POWER IMPACTS

Site Specific Factors	Feedstock Procurement		Conversion Plants	
	Wood Residue	Coal	Wood	Coal
Climatology and Meteorology	0	0	-1	-1
Air Quality	-1	-1	-6	-6
Surface Water Availability	0	-1	-1	-1
Surface Water Quality	-1	-6	-1	-1
Groundwater Availability	0	-7	0	0
Groundwater Quality	0	-7	-6	-6
Soils, Geology	-7	-9	-6	-8
Land Availability	-1	-1	-6	-6
Ecology	1	-7	-6	-6
Aesthetic Resources	1	-8	-7	-8
Historical, Archaeological Resources	0	-7	-6	-6
Community Economy	5	5	5	5
Community Population and Services	0	-6	-1	-2
Labor Availability	1	-1	-1	-1
Power Availability	0	0	5	10
Transportation Availability	-6	-6	-6	-6
TOTAL	-8	-62	-44	-43

STRAW/MANURE AND COAL TO SYNTHETIC PIPELINE GAS

The hypothetical biogas and HYGAS conversion plants would produce SPG in the midwest region. The large difference in plant capacities should be kept in mind in this comparison of their economics and environmental impacts.

Economic Comparison of SPG Production — Scenario 2

Both conversion plants can be considered advanced processes for production of SPG. HYGAS is a second-generation gasification process not yet in the commercial stage. Anaerobic digestion is an old process, but this conceptual commercial-scale plant is not yet demonstrated technology. The steam-oxygen HYGAS process was the best economic case of the six gasification processes evaluated in the 1976 C. F. Braun report (6). Anaerobic digestion of biomass residues is considered by some a promising route to low-cost methane gas.

Economic factors of the two conceptual conversion plants are compared in Table 112 for both private and utility financing. The 250 MMM Btu/day capacity plant is generally considered a reasonable commercial scale for high-Btu gasification processes. The biogas plant, at nearly one-fortieth the capacity, might suffer in the comparison, but a much larger facility could not be envisioned in this scenario. Plant thermal efficiency certainly favors the HYGAS facility by a factor of two, a difference primarily related to the conversion processes themselves.

A comparison of the cost items in Table 112 on the basis of energy output indicates unfavorable cost ratios from 2.5 to 4 or more for SPG from straw and manure. A portion of the difference can be attributed to the low biogas plant capacity compared with the HYGAS capacity, but the low conversion efficiency is a more critical difference. The biogas annual operating cost (excluding feedstock) of $2.97/MM Btu is, by itself, higher than current prices for most fuels. If the biogas plant's undigested residue could be sold as cattle feed, for example, a large byproduct credit could improve the biogas economics considerably.

Without including the cost of feedstock, the SPG production cost for the biogas plant is about three times that for the HYGAS facility wieh either utility or private financing as used in this study. Compared with first-generation coal gasification technology (Lurgi), biogas-derived SPG may be only twice as costly, however. It should be noted that other estimates (9, 10, 11, 12) of SNG costs by digestion and gasification of biomass are more optimistic ($3 to $5/MM Btu, excluding feedstock costs). The gas cost examples shown in Table 112 include the costs of delivered feedstocks at prices which might be reasonable in this midwest scenario today. Sensitivity of gas costs to feedstock costs is shown in Figure 41. Various relative feedstock cost scenarios can be considered for the future, but it seems clear that the cost of SPG diverges in favor of coal gasification (or at least HYGAS) at increasing feedstock prices.

It is not apparent how biogas-derived SPG can be competitive economically with coal gasification on a large commercial scale, since conversion efficiencies are relatively low and practical plant capacities are limited. This comparison,

TABLE 112. ECONOMIC COMPARISON OF STRAW/MANURE AND COAL TO SPG

Element	Straw/Manure to SPG (6.66 MMM Btu/Day)	Coal to SPG (HYGAS) (250 MMM Btu/Day)
Feedstock Input, MM Btu/yr	5,670,000	118,360,000
SPG Output, MM Btu/yr	2,188,600	82,125,000
Thermal Efficiency, %	31.9	69.7
Capital Cost		
$ Million	85.2	1,213.2
$/MM Btu Per Day (Net)	12,800	4,850
Operating Cost*		
$ Million/yr	6.5	53.6
$/MM Btu	2.97	0.65
Base Production Cost*		
Utility, $/MM Btu	7.68	2.42
Private, $/MM Btu	10.63	3.37
Example Cost of SPG**		
Utility, $/MM Btu	9.48	3.66
Private, $/MM Btu	12.43	5.02

* Excludes feedstock cost.

** Includes straw at $10/ton ($.70/MM Btu), manure at $2/ton ($.68/MM Btu), and coal at $15/ton ($.85/MM Btu).

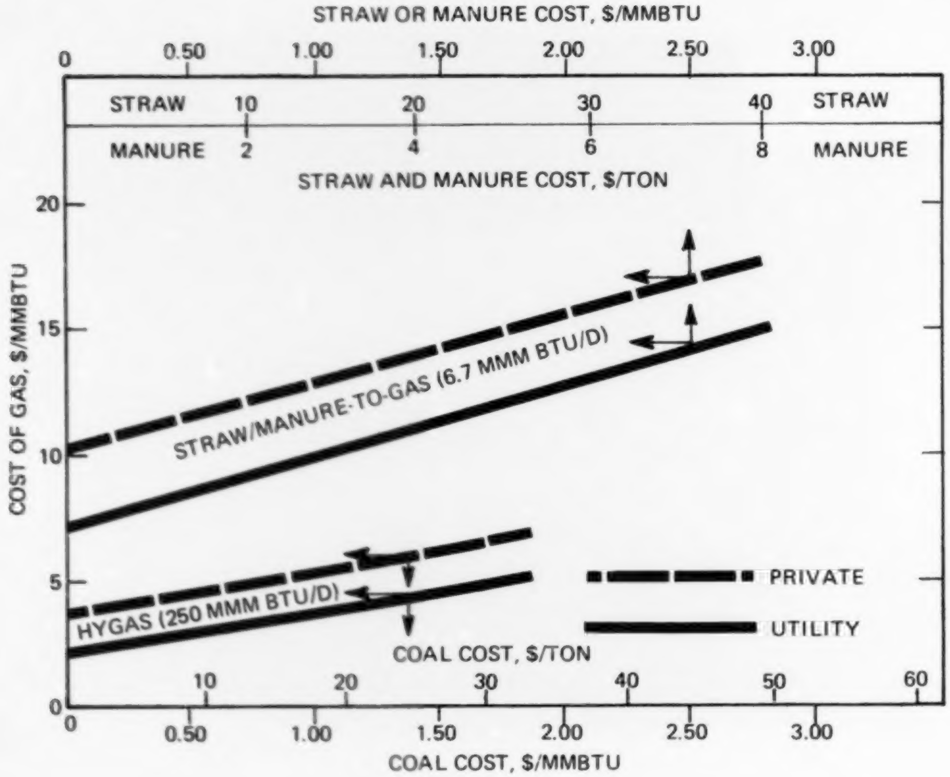

Figure 41. Effect of feedstock cost on the cost of synthetic pipeline gas (SPG).

at least, would suggest a different direction for this intrinsically wet conversion process; namely, small-scale plants using wet biomass materials available in high local concentrations. Using fresh cattle manure from a large (100,000 head) confined feedlot in an onsite biogas plant is an example. The product could be medium-Btu gas for local industrial fuel or gas-turbine power generation. Improvement in the conversion efficiency to methane is also needed.

Environmental Comparison — Scenario 2

Feedstock Procurement--

As in Scenario 1, the actual collection of feedstock materials will be the major source of environmental impact. These surface activities will alter soils, geology, topography, and land use directly. In turn, these direct impacts affect air and water quality, ecology, and future uses. The impacts of collection of straw/manure and coal are discussed below and are summarized in Table 113.

Air Quality--Short-term increases in particulate concentrations (resulting from fugitive dust) are expected from both feedstock procurement activities. The actual quantities of fugitive dust will depend on the acreage exposed to wind erosion. Straw collection, if carefully managed, will probably result in less fugitive dust even though the acreage affected will probably be much greater than the 100 acres per year disturbed by surface coal mining. On a regional scale, neither activity is likely to affect air quality significantly.

Surface Water--Straw procurement may expose highly erodible soils to water erosion, so careful analysis of the area will be necessary to determine in which fields partial collection should be practiced. No impacts on water availability are anticipated.

Coal mining may remove or redirect surface runoff, altering downstream flows. This alteration may be partially mitigated by reclamation, but any topographical change in the mine area could indirectly affect water availability.

Erosion from stockpiled soils and subsoils, from strip-mined land, and from coal piles could affect water quality. Uses of erosion control methods, settling ponds, and prompt reclamation/revegetation will minimize this adverse impact.

Groundwater--Little or no discernible impact on groundwater is expected from straw or manure collection. Coal mining, as in Scenario 1, could affect groundwater availability by:

- Interrupting recharge
- Dewatering the mine site
- Cutting or removing shallow aquifers

Groundwater quality could be adversely affected by changing the composition of the overburden, thereby affecting the sources of groundwater chemicals

TABLE 113. IMPACT SUMMARY FOR SITE SPECIFIC FACTORS — FEEDSTOCK PROCUREMENT

Site Specific Factors	No Discernible Impact	Beneficial Impact	Adverse Impact (a)	Short Term	Long Term	Direct	Indirect	Mitigating Measures (b)
WHEAT STRAW AND MANURE PROCUREMENT MIDWESTERN U.S.								
Climatology and Meteorology	X							
Air Quality			I		X	X		A
Surface Water Availability	X							
Surface Water Quality			I	X		X		A
Groundwater Availability	X							
Groundwater Quality	X							
Soils and Geology			I-M		X	X		A
Land Availability	X							
Regional Ecology and Critical Habitats	X							
Aesthetic Resources	X							
Historical, Archaeological Resources	X							
Community Economy		X(d)						
Community Population and Services	X							
Labor Availability		X						
Power Availability	X							
Transportation Availability			I		X	X		
COAL PROCUREMENT, WESTERN U.S.								
Climatology and Meteorology	X							
Air Quality			I-M	X		X		
Surface Water Availability			I	X		X		
Surface Water Quality			I		X	X		A
Groundwater Availability			I-M		X	X		
Groundwater Quality			I-M		X	X		
Soils and Geology			M		X	X		
Land Availability			I	X		X		A
Regional Ecology and Critical Habitats			I-M		X	X		A
Aesthetic Resources			M		X	X		A
Historical, Archaeological Resources			I-M		X	X		A
Community Economy		X(d)						
Community Population and Services	X							
Labor Availability		X						
Power Availability	X							
Transportation Availability			I		X	X		

(a) Key for symbols used in adverse impact ratings:
S = Potentially significant
M = Moderate
I = Potentially insignificant

(b) Key for symbols used in mitigating measures ratings:
A = Mitigating measures described in text assumed to be implemented

(c) Assumes no other large scale development in the area coincident with power plant development or synthetic fuel.

(d) Assumes cooperation between plant and government agencies to promote reasonable, economically sound growth.

(e) Assumes power production or fuel production is a benefit to the community outweighing minor power consumption during construction or during operation.

and minerals, and by allowing one or more lower-quality aquifers to connect with a better-quality supply. Detailed studies on the area would be necessary to determine whether or not these long-term impacts can occur, and whether or not such impacts would be important to regional water use.

Soils and Geology--In addition to the potential for increased wind and water erosion, removal of straw could contribute to decreased soil productivity. Since the straw is commonly plowed into the ground at planting time, it contributes to topsoil stability and organic content. Some or all of this contribution will be eliminated. The use of organic sludges (residue) from anaerobic digestion as soil amendments may compensate partially for this loss, but the nutritive content of the sludges will be less than the straw and additional fertilizers may be necessary.

Manure is usually used as a soil amendment, although not at the collection sites. Use of manure as feedstock, therefore, reduces the availability of soil amendments and could force local reliance on chemical fertilizers and conditioners.

As in Scenario 1, coal mining can affect soil productivity, stratification, concentrations of toxic materials, density, and topography. While 100 acres a year is not significant on a regional scale, in context with other mining activities the regional impact could be important and long-term.

Land Availability--Straw and manure collection will not affect land availability or use; sufficient acreage must be available to supply the necessary feedstock but, with proper management and with use of soil conditioners, the wheat fields could continue is use.

Coal mining will commit 100 acres per year, which will be reclaimed immediately after use. This constitutes a small land commitment regionally, and restoration to agricultural use is technically and economically feasible. Future use of the area for coal mining, however, will be foreclosed, since the mineral will have been consumed.

Ecology--Since the straw/manure collection is restricted to agricultural lands, no discernible environmental impacts on wildlife are expected. Coal mining, however, could result in a reduction of grassland vegetation and its associated animal populations. Even after revegetation, this habitat may not be as productive as wildlife habitat. Reclamation for wildlife use may require inclusion of more varieties of plant species, adding significantly to technical difficulties (plant propagation, proper watering, and fertilizers) as well as costs. Since native prairie species are not common, loss of such habitat could constitute an important impact.

Aesthetics--Straw and manure collection should have no discernible effect on the visual quality of the collection sites. Coal mining, on the other hand, will result in contrasts in color, land form, and texture on 100 acres each year. Although reclamation will be a continuing process, there will always be one or more areas at the mine site which are being worked. These contrasts will be aesthetically displeasing and may persist for a period following the cessation of mining.

Historic and Archaeological Resources--Straw and manure collection will not affect any historic or archaeological resources, since no physical disruption of land surface or structures will result. The coal mine could uncover subsurface relics, and premining surveys may be used to locate, preserve, or salvage resources. The presence of a historic landmark on the mine site might prohibit mining activity in that area, a possible constraint to feedstock procurement.

Social and Economic Effects--Both feedstock procurement activities will create jobs (30 to 50 for straw/manure collection, for example) and infuse new money into the regional economies. The local labor pools are expected to be sufficient to supply all needed employees, and little growth is anticipated nearby as a result of these activities alone. Development of several other large strip mines in the same western mine area could stress the labor pool and induce significant community growth.

Conversion Plants--

Air, water, and solid waste emissions are expected to be the major sources of environmental impact for synthetic gas plants. These emissions could directly affect air and surface water quality and land use, and indirectly affect groundwater quality. Section 4 described the potential emission concentrations. In this section, straw/manure-to-gas (biogas) and coal-to-gas (HYGAS) plants are environmentally compared assuming the same site in midwestern U.S. Table 114 summarizes this comparison.

Climatology and Meteorology--About 8200 lb/hr of water vapor will be released by the biogas plant cooling tower, while 405,000 lb/hr will be released by HYGAS. On a MMSCFD basis, the biogas plant (7 MMSCFD) will release somewhat less water vapor than the HYGAS plant (274 MMSCFD). Maximum use of air cooling will keep the HYGAS cooling water demand low, although total heat rejection to the atmosphere is considerably greater for HYGAS on a relative gas output basis. On cool humid days, local fogging could occur for either plant. In addition, icing could occur on days when the plume came to the ground and the temperature was below freezing. The relative impact from the HYGAS plant will be larger.

Air Quality--The biogas plant will release NO_x (104 tons/year), SO_x (398 tons/year), CO (less than 21 tons/year), and HC (less than 21 tons/year) as well as fugitive dust and potential odors from the manure stockpile. This facility will probably meet standards in the area, although new source tradeoffs may be necessary. In addition, 20 tons per year of salts will be deposited downwind of the cooling tower.

The HYGAS plant may release NO_x (1900 tons/year), SO_x (4600 tons/year), CO (3500 tons/year), miscellaneous hydrocarbons (including methane, ethane), COS, and hydrogen sulfide as well as trace quantities of potentially toxic organic materials. On a MMSCFD basis, these emissions are similar to biogas emissions except for the potentially hazardous organic and reduced sulfur compounds. Local adverse impacts may not be significantly different from those of biogas, but additional pollution controls may have to be implemented to control vapor emissions. In the HYGAS plant, about 40 tons per year of

TABLE 114. IMPACT SUMMARY FOR SITE SPECIFIC FACTORS — STRAW/MANURE AND COAL TO SYNTHETIC PIPELINE GAS

Site Specific Factors	No Discernible Impact	Beneficial Impact	Adverse Impact (a)	Short Term	Long Term	Direct	Indirect	Mitigating Measures (b)
BIOGAS, 7 MMSCFD METHANE GAS PLANT, MIDWESTERN U.S.								
Climatology and Meteorology			I	X		X		
Air Quality			I(c)		X	X		A
Surface Water Availability			I	X		X		A
Surface Water Quality			I	X		X		A
Groundwater Availability			I		X	X		
Groundwater Quality			I		X		X	A
Soils and Geology			I-M		X	X		A
Land Availability			I(c)		X	X		
Regional Ecology and Critical Habitat			I		X	X		A
Aesthetic Resources			I-M		X	X		A
Historical, Archaeological Resources			I		X	X		A
Community Economy		X(d)						
Community Population and Services			I	X		X		A
Labor Availability			I	X		X		A
Power Availability		X(e)						
Transportation Availability			I		X	X		A
STEAM-OXYGEN HYGAS, 250 MMSCFD COAL GASIFICATION PLANT, MIDWESTERN U.S.								
Climatology and Meteorology			I	X		X		
Air Quality			I(c)		X	X		A
Surface Water Availability			I	X		X		A
Surface Water Quality			I	X		X		A
Groundwater Availability			I		X	X		
Groundwater Quality			I		X		X	A
Soils and Geology			I-M		X	X		
Land Availability			I(c)		X	X		A
Regional Ecology and Critical Habitat			I		X	X		A
Aesthetic Resources			I-M		X	X		A
Historical, Archaeological Resources			I		X	X		A
Community Economy		X(d)						
Community Population and Services			I-M	X		X		A
Labor Availability			I-M	X		X		A
Power Availability		X(e)						
Transportation Availability			I		X	X		A

(a) Key for symbols used in adverse impact ratings:
S = Potentially significant
M = Moderate
I = Potentially insignificant

(b) Key for symbols used in mitigating measures ratings:
A = Mitigating measures described in text assumed to be implemented

(c) Assumes no other large scale development in the area coincident with power plant development or synthetic fuel.

(d) Assumes cooperation between plant and government agencies to promote reasonable, economically sound growth.

(e) Assumes power production or fuel production is a benefit to the community outweighing minor power consumption during construction or during operation.

salts will be deposited downwind of the cooling tower. Cooling-tower drift will probably contain organics resulting from recycling of process effluents to the cooling system.

Surface Water--The biogas facility will require about 43 gallons of water per million Btu production (or 40 gallons of surface water per 1000 SCF of product gas). Treatment and internal recycling will reduce the consumption rate. The water consumption by HYGAS will be about 11 gallons per million Btu. As noted earlier, the HYGAS plant utilizes air cooling to lower water consumption, and internal recycling further reduces consumptive use. Neither facility should seriously affect surface water availability.

Discharges from the biogas plant will contain TDS, TSS, residual chlorine, small amounts of oil and grease, BOD, nitrogen, and phosphorus. The quantities discharged (about 150 gpm process effluent and 50 gpm storm runoff) and the concentrations of material in the effluent are not expected to be significant unless hazardous compounds are present. The HYGAS plant will discharge no process wastewater, but will discharge about 150 gpm (average annual flow) of storm runoff containing TSS and oil and grease. Upsets in the closed process water recycle systems could result in discharge of dissolved and suspended pollutants and pose a problem to surface water quality. Proper management of runoff from coal storage, the onsite landfill and process areas, including containment and treatment, if necessary, will minimize the potential for serious degradation of surface receiving water.

Groundwater--About three gallons of groundwater per MSCF product gas will be used in the biogas plant, while the HYGAS plant will use no groundwater. The impact of this consumption will depend on other uses of the supply but the effect is expected to be minor.

At this time, sludges from biogas are assumed to be applied as a soil amendment to the fields from which straw is collected. While these organic sludges may leach during interim storage and after spreading, the contamination potential for groundwater is expected to be small. Interim storage sites (offsite) will probably have to be diked and lined to prevent percolation of nitrates and trace organics to the groundwater.

HYGAS solid wastes will have potentially toxic materials such as heavy metals, trace organics, and other matter which could contaminate groundwater through leaching. If the western mine site is used for disposal prior to reclamation, the area may need special preparation to minimize groundwater contact. The onsite plant solid waste landfill area will be clay lined, and the coal storage sites should be lined to prevent groundwater contamination.

Soils and Geology--Construction will affect the landform and surface of 140 acres for the biogas plant and 440 acres for the HYGAS plant. Again, the HYGAS facility demonstrates an economy of scale with much less land committed per MMSCFD of gas production. Onsite, the changes will be significant and permanent, particularly the solid waste landfill for HYGAS. The overall regional impact will be low.

Land Availability--Commitment of 140 acres to the biogas plant and 440 acres to the HYGAS plant constitutes a limit on developable lands in the vicinity of the site. The use of a 440-acre buffer zone for HYGAS will not be incompatible with agricultural, grazing, or other low-intensity uses, but constraints on land acquisition could arise. On a regional basis, land availability should not be significantly affected.

Ecology--Assuming the site to be primarily agricultural, ecological effects should be minimal regardless of the process used. However, some wildlife habitat (a maximum of 140 acres for the biogas plant and 400 acres for the HYGAS plant) would be removed if the area were used for grazing, or if woodlots or fence rows were affected. Care in siting should further reduce this impact.

Impacts on nearby wildlife and vegetation from air or water quality degradation, salt deposition from cooling-tower drift, or entrainment in intake water systems may be greater for HYGAS because this plant has greater total emissions. But per Btu, the biogas plant may have the greater relative impact.

Aesthetics--Both facilities will impose an industrial appearance on a rural site, and the magnitude of visual contact will be proportional to the size of the structures (stacks, reaction vessel trains, cooling towers, rail yards, etc.). In addition, live coal piles and wastewater ponds will affect the appearance of the HYGAS site, while a possible odor problem from manure storage could affect the biogas plant site. Use of landscaping and buffer zones (440 acres for HYGAS) as well as plant layout could reduce the local impact on aesthetics.

Historic and Archaeological Resources--Care in siting will reduce the potential for adverse impact on historic or cultural resources. Should any subsurface relics be discovered during siting or construction, salvage and protection measures will be implemented.

Social and Economic Effects--Approximately 100 full-time operation jobs will be provided by the biogas plant, while the HYGAS plant will required more than 700 permanent employees. These facilities will also require several hundred (biogas) to 300 (HYGAS) construction workers. These jobs and their resultant wages will benefit the local economy as will local spending, capital expenditures, and expanded tax base. Some small increases in population and demand for services may result in this rural area, and labor training programs and recruitment may be necessary to staff the jobs for both plants.

Both plants will produce synthetic pipeline gas which can be used to generate energy. While coal conversion consumes a nonrenewable resource, it is more efficient than biogas conversion (less feedstock used per Btu produced). Therefore, the return would be a cheaper synthetic gas from HYGAS than biogas which, in turn, would result in less cost for energy generation.

Consumption of Resources--Table 115 shows the natural resource consumption expected from each plant. The HYGAS process and the economy of scale result in less materials consumed per million Btu of output than the biogas plant.

TABLE 115. RESOURCES COMMITTED TO THE SYNTHETIC GAS PLANTS*

Resource	Straw/Manure to Gas 7 MMSCFD	Coal to Gas 274 MMSCFD
Land	0.5 acre/MM Btu/hr	0.07 acre/MM Btu/hr**
Feedstock	600.4 lb/MM Btu	163.8 lb/MM Btu
Auxiliary Fuels	544 Btu/MM Btu	134 Btu/MM Btu
Chemicals	5.6 lb/MM Btu	0.071 lb/MM Btu
Auxiliary Power	19.6 kW/MM Btu/hr	0
Water	42.9 gal/MM Btu	11.1 gal/MM Btu
Manpower	0.09 mh/MM Btu	0.019 mh/MM Btu

*From Tables 56 and 70.
**Increases to 0.14 acre/MM Btu if a 440 acre buffer zone is included.

Summary of Scenario 2--
If the qualitative assessments summarized in Tables 113 and 114 were assigned the numerical values in Table 110 and summed without weighting environmental aspects of the site, the biogas plant and the HYGAS plant would have similar regional impacts per volume (or Btu) of product gas. Feedstock procurement for the HYGAS plant, however, would potentially have significantly greater impact than straw and manure collection for the biogas plant (Table 116). Mitigation of surface mining impacts would be critical if the two gas production cycles were to be made environmentally comparable. In other words, the biogas facility would be more environmentally suitable in this scenario region, principally because of lower feedstock procurement impacts. Additional study is needed on the nature of air, water, and solid waste emissions from the HYGAS process to determine if hazardous substances are a problem.

TABLE 116. SUMMARY OF STRAW/MANURE AND COAL TO SYNTHETIC GAS IMPACTS

Site Specific Factors	Feedstock Procurement		Conversion Plants	
	Straw/Manure	Coal	Straw/Manure	Coal
Climatology and Meteorology	0	0	-1	-2
Air Quality	-6	-2	-6	-6
Surface Water Availability	0	-1	-1	-1
Surface Water Quality	-1	-6	-1	-1
Groundwater Availability	0	-7	-6	-6
Groundwater Quality	0	-7	-6	-7
Soils, Geology	-7	-8	-7	-6
Land Availability	0	-1	-6	-6
Ecology	0	-7	-6	-6
Aesthetic Resources	0	-8	-7	-7
Historical, Archaelogical Resources	0	-7	-6	-7
Community Economy	5	5	5	5
Community Population and Services	0	0	-1	-2
Labor Availability	1	1	-1	-2
Power Availability	0	0	5	10
Transportation Availability	-6	-6	-6	-6
TOTAL	-14	-54	-51	-48

WOOD AND COAL TO SYNTHETIC FUEL OIL

The hypothetical wood and H-Coal liquefaction plants would produce low sulfur synthetic fuel oil in the northeastern region of the U.S. Boiler fuel is assumed to be the most likely product use in this region. Section 5 presented details of the two conversion cases.

Economic Comparison of Fuel Oil Production — Scenario 3

The production capacity of the H-Coal plant is nearly 40 times that of the wood-to-oil plant. Table 117 summarizes economic factors for the two similar conversion processes with a large capacity difference. Capital investment for wood-to-oil is more than twice that for H-Coal on a BPD production basis. A larger biomass conversion plant would look better economically, but wood residue availability limits the practical plant capacity in this scenario. The lower conversion efficiency is also a penalty. Annual operating costs differ by a factor of nearly four, and the $18.88 per barrel annual cost for the wood-to-oil plant reflects large labor and purchased power expenses.

Base production costs in Table 117 exclude the feedstock costs. For both private and utility financing, wood-derived fuel oil is 2.5 to 3 times more costly to produce, at least in this comparison. The example fuel oil costs reflect the inclusion of forest residue at $10 per ton and high sulfur coal at $25 per ton. Neither plant appears to produce an economically competitive boiler fuel, if these feedstock costs can be considered reasonable estimates for early 1978. The wood-derived oil is about twice as expensive as the coal-derived oil on both financing bases. For comparison, a recent SRI report (11) gives an oil cost (utility financing) of about $31.20 per barrel ($5.37/MM Btu) for a 5268 BPD wood liquefaction plant using the same wood cost of $1.00/MM Btu. This SRI example shows the effects of an economy of scale and a higher conversion efficiency (52 percent versus 42.1 percent).

The relative impacts of wood and coal costs on the cost of synthetic fuel oil are illustrated in Figure 42. On an equivalent $/MM Btu feedstock basis, the roughly parallel lines indicate that an increase in feedstock cost results in about the same percentage increase in oil cost for both cases. In absolute costs, the wood-derived oil is much more sensitive to wood cost. Again, the effect is noted that the cost of the feedstock is very important in small-capacity plants. Biomass conversion is unlikely to be competitive with large-scale coal conversion unless biomass feedstocks are relatively much lower in cost and biomass conversion efficiencies are improved.

As noted in Section 5, nearly half of the plant wood feedstock is consumed in the production of synthesis gas for the liquefaction reaction. Conversion efficiency improvements are certainly possible in this liquefaction process. A larger scale plant might be possible in an area with greater residue resources (at a low cost). However, many favorable circumstances would be needed to overcome the apparent economic advantage of a large coal liquefaction facility.

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TABLE 117. ECONOMIC COMPARISON OF WOOD AND COAL TO SYNTHETIC FUEL OIL

Element	Wood to Oil (1,764 BPD)	Coal to Oil (H-Coal) (66,856 BPD)
Feedstock input, MM Btu/yr	6,550,000 (HHV)	220,810,000 (HHV)(a)
Fuel Oil Output, MM Btu/yr	3,704,000 (HHV)	139,186,000 (LHV)(b)
Thermal Efficiency, %	42.1	65.5(b)
Capital Cost		
$ Million	99.1	1,640
$/BPD (Net)	56,180	24,530
Operating Cost(c)		
$ Million/yr	11.1	108.8
$/bbl(d)	18.88	4.88
Base Oil Production Cost(c)		
Utility, $/bbl(d)	39.23	13.72
Private, $/bbl	51.99	20.37
Sample Fuel Oil Cost(e)		
Utility, $/bbl(d)	50.37	24.19
Private, $/bbl(d)	63.13	30.88

(a) 212,367,000 MM Btu/yr (LHV).
(b) Sum of naphtha and heavy fuel oil.
(c) Excludes feedstock cost.
(d) For a $/MM Btu basis, use 6.3 MM Btu/bbl for wood-derived oil and 6.246 MM Btu/bbl (LHV) for coal-derived oil (naphtha plus fuel oil).
(e) Includes wood residue at $10/ton ($1.00/MM Btu) and coal at $25/ton ($1.05/MM Btu).

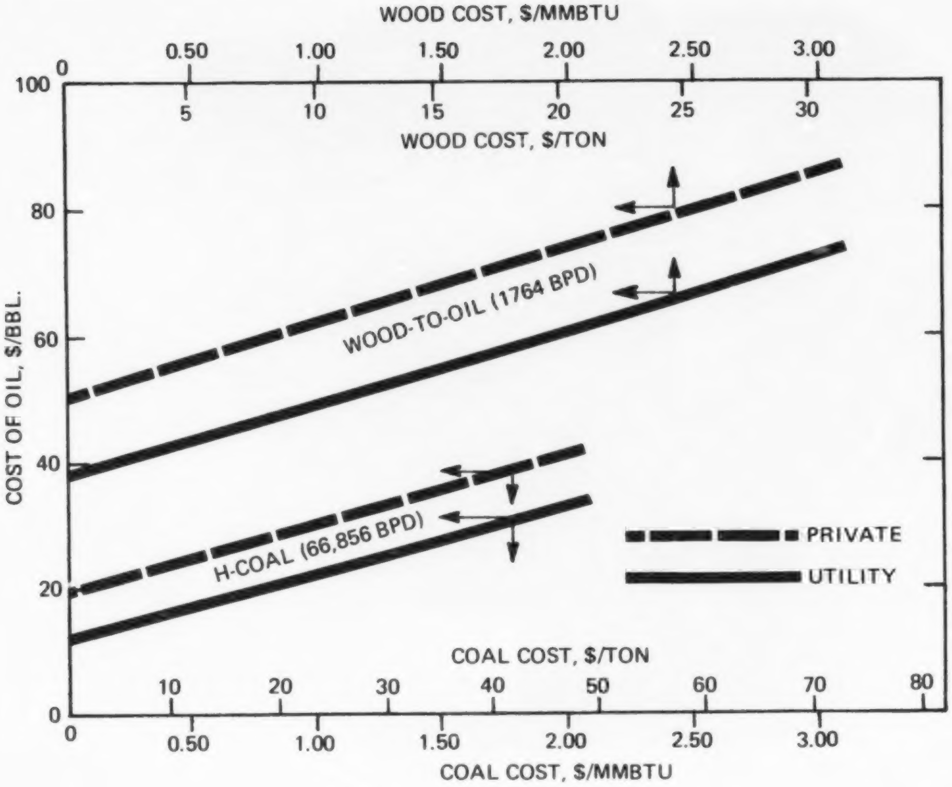

Figure 42. Effect of feedstock cost on the cost of synthetic fuel oil.

Environmental Comparison — Scenario 3

Feedstock Procurement--

Mining of coal and gathering of wood residue require certain physical activities which will affect the environment. In general, soils, geology, topography, and water are affected by deep coal mining while wood residue collection, as in Scenario 1, may affect soil productivity, erosion, and water quality. In the following paragraphs and in Table 118, the potential impacts of feedstock procurement for wood and coal liquefaction are summarized.

Air Quality--Short-term increases in fugitive dust concentration may result from both feedstock procurement operations. Wind erosion of exposed soils may result from excess wood residue removal, while stockpiling and transport of coal and disposal of mine rock will contribute to fugitive dusts as well. Use of dust control measures and care in residue collection, coal storage, and transport can mitigate potential impacts.

Surface Water--Increased erosion in areas stripped of forest residues could result in increased sediment loads in streams. Slopes are particularly susceptible to erosion. Careful management of residue collection will minimize this effect.

In deep mines, it may be necessary to dewater the mine area. This water, if discharged directly to surface waters, could degrade water quality significantly. Acid mine drainage is of particular concern in the eastern U.S. which already has water quality significantly affected by mine and industrial waste discharges. In addition, disposal of mine rock wastes in shallow valleys may contribute to increased sediments in surface waters. Pollutants in runoff and leachate from the waste piles can degrade water quality. Since shallow valleys may be direct conduits to surface water bodies, dikes and other protective measures may have to be implemented to protect downstream water quality.

No impacts on surface water availability are expected from either procedure, although coal waste disposal in shallow valleys could affect flow patterns in small tributaries.

Groundwater--Wood residue collection should not affect the quality or quantity of groundwater. Mine water is a groundwater supply, however, and dewatering of the coal mines may interrupt flow in some aquifers. Of particular concern would be the good-quality water expected in one of the three proposed mines.

Soils and Geology--Since wood refuse contributes over time to soil stability and organic content, removal of the residues could reduce soil productivity and contribute to the loss of topsoil through wind and water erosion. A loss of nutrients such as nitrogen, potassium, phosphorus, and sulfur may require use of chemical fertilizers or alternative soil conditioners to ensure continued productivity of the forest-land soil.

Deep mining may affect soils through mine rock disposal by altering the surface composition, texture, and topography in the shallow valleys. In addition, extraction of coal could contribute to future subsidence over the mine itself.

TABLE 118. IMPACT SUMMARY FOR SITE SPECIFIC FACTORS — FEEDSTOCK PROCUREMENT

Site Specific Factors	No Discernible Impact	Beneficial Impact	Adverse Impact (a)	Short Term	Long Term	Direct	Indirect	Mitigating Measures (b)
FOREST RESIDUE PROCUREMENT, NEW ENGLAND								
Climatology and Meteorology	X							
Air Quality			I	X		X		
Surface Water Availability	X							
Surface Water Quality			I	X		X		A
Groundwater Availability	X							
Groundwater Quality	X							
Soils and Geology			I-M		X		X	A
Land Availability			I	X		X		A
Regional Ecology and Critical Habitats		X						
Aesthetic Resources		X						
Historical, Archaeological Resources	X							
Community Economy		X(d)						
Community Population and Services	X							
Labor Availability		X						
Power Availability	X							
Transportation Availability			I		X	X		
COAL PROCUREMENT, EASTERN U.S.								
Climatology and Meteorology	X							
Air Quality			I	X		X		A
Surface Water Availability	X							
Surface Water Quality			I-M		X	X		A
Groundwater Availability			I-M		X	X		
Groundwater Quality			I		X		X	
Soils and Geology			M		X	X		
Land Availability			I		X	X		A
Regional Ecology and Critical Habitats			M-S		X	X		A
Aesthetic Resources			M	X		X		A
Historical, Archaeological Resources	X							
Community Economy		X						
Community Population and Services	X							
Labor Availability	X							
Power Availability	X							
Transportation Availability			I	X	X			

(a) Key for symbols used in adverse impact ratings:
S = Potentially significant
M = Moderate
I = Potentially insignificant

(b) Key for symbols used in mitigating measures ratings:
A = Mitigating measures described in text assumed to be implemented

(c) Assumes no other large scale development in the area coincident with power plant development or synthetic fuel.

(d) Assumes cooperation between plant and government agencies to promote reasonable, economically sound growth.

(e) Assumes power production or fuel production is a benefit to the community outweighing minor power consumption during construction or during operation.

Land Availability--Between 20,000 and 70,000 acres per year will be required for forest residue collection. Since regrowth of forests in cutover areas is necessary before a collected area can be used again, it is not likely that the acreage used in any given year will be used again during the life of the wood liquefaction facility. Therefore, many thousands of acres of suitable land must be available for feedstock procurement, but use of this land, if available, should not affect alternative land use or development.

The deep mine itself does not commit a large amount of surface area. However, mine rock disposal may require large areas and alternative uses of these areas may be restricted after disposal is complete. Therefore, use of disposal sites might have some impact on land availability, particularly in highly developed areas like the coal-mining portions of the eastern U.S.

Ecology--As in Scenario 1, removal of forest residues may physically disturb forest floor communities of animals, alter the rate of forest regeneration by altering forest floor soils, and displace wildlife due to the presence of man in the area. Because of the acreage committed to residue collection, this disturbance will be widespread regionally although its significance will be small because a site will be used only once, followed by the natural (or man-assisted) recovery of that system.

Removal of forest floor debris may benefit the forest by eliminating forest fire fuels and by removing the habitat of known insect pests or disease organisms. A long-term benefit to forest productivity could then result.

A regional reduction in habitat and wildlife could result from mine rock disposal from the coal mines. Since the shallow valley disposal sites may also be riparian vegetation types, and since industrial development in the eastern U.S. has reduced wildlife habitat acreage (particularly riparian habitats), this disposal could cause significant adverse impacts on regional ecology.

Aesthetics--Forest residue collection will result in a change in the visual appearance of the woodland affected (about 20,000 to 70,000 acres a year). This change could be positive, particularly in a fir or pinewoods where an open parklike appearance would result. The change might be less noticeable in a hardwood or mixed forest, where underbrush normally conceals the forest floor.

The deep mines should not affect the aesthetics beyond the actual mine shaft and associated buildings. However, mine rock disposal will result in a loss of vegetation, a contrast in color and texture, and changes in topography which on a regional scale may be important. The further reduction of open space and forested vistas in a heavily developed region such as the eastern U.S. coal province could constitute a moderate to significant long-term adverse effect. This impact would be moderated over time by reclamation and revegetation of the disposal sites.

Historic and Archaeological Resources--Neither forest residue collection nor deep mine operation should affect historic or archaeological sites. Mine rock disposal would be constrained by the existence of known sites; however, surveys prior to selection of disposal sites will permit avoidance of such resources.

Social and Economic Effects--Between 30 and 50 jobs will be created by forest residue collection, as in Scenario 1. Associated wages and spending as well as several million dollars per year paid for the wood residues will benefit the community. No adverse impacts on community services or labor availability are expected.

Coal mining will provide full-time employment as well. In the eastern U.S. coal province, skilled labor should be readily available, and no drains on services or population are expected. On the order of $200 million per year will be paid for the coal, a benefit to the local economy.

Conversion Plants--

Construction and operation of wood or coal liquefaction plants will affect the hypothetical plant site and vicinity, primarily through generation of air and water emissions and solid wastes. As in Scenarios 1 and 2, the emissions will directly affect air and surface water quality, soils, topography, and land use and indirectly affect ecology and groundwater quality. Section 5 detailed the emissions expected; the following paragraphs and Table 119 summarize these impacts assuming similar (but not the same) plant sites. The wood-to-oil site is in New England, while the coal-to-oil (H-Coal) site is in the eastern U.S. coal province.

Climatology and Meteorology--The wood liquefaction plant cooling tower will release approximately 62,500 lb/hr of water vapor to the atmosphere, while H-Coal plant towers will release about 2.2 MM lb/hr. The 25,000 TPD coal facility has a slight economy of scale in this respect over the 2000 TPD wood-to-oil plant. While impacts will be short-term and localized, both facilities have the potential to increase fogging on cool, humid days; and, when the temperatures are below freezing, icing could occur. The absolute magnitude of impact for the H-Coal plant is much greater, of course.

Air Quality--The wood-to-oil conversion plant is expected to produce over 100 tons per year of particulate emissions and could be subject to new source tradeoff (offset) conditions. Other potential air problems could result from hydrocarbon vapors released from product storage which could aggravate an existing photochemical oxidant problem. Small quantities of NO_x, SO_x, CO, and H_2 will also be released, and cooling-tower drift will contain small amounts of hydrocarbons if process wastewater is recycled to the cooling water system. About 10 tons per year of salt will be deposited in the area from cooling-tower drift losses.

The H-Coal plant will release significant quantities of fugitive dust from coal handling. Other emissions will include NO_x, SO_x, CO, hydrocarbons such as methane, H_2S, COS, and also NH_3. Trace organic compounds which could be toxic, carcinogenic, or mutagenic might be released from product storage, vent gas stacks, and cooling towers. Salt emissions in cooling-tower drift will be about 600 tons per year. Some H-Coal vent gas streams might require special treatment to reduce toxic trace materials and hydrocarbon emissions. In a relatively developed area such as the industrial eastern U.S., new sources of SO_x, NO_x, and HC could be significant in nonattainment areas, and could make implementation of emission offsets by the plant necessary.

TABLE 119. IMPACT SUMMARY FOR SITE SPECIFIC FACTORS — WOOD AND COAL TO FUEL OIL

Site Specific Factors	No Discernible Impact	Beneficial Impact	Adverse Impact (a)	Short Term	Long Term	Direct	Indirect	Mitigating Measures (b)
WOOD-TO-OIL, 2000 TPD PLANT IN NEW ENGLAND								
Climatology and Meteorology			I	X		X		
Air Quality			I(c)		X	X		
Surface Water Availability	X							
Surface Water Quality			I	X		X		A
Groundwater Availability	X							
Groundwater Quality			I		X		X	A
Soils and Geology			I		X	X		
Land Availability			I(c)		X	X		A
Regional Ecology and Critical Habitats			I		X	X		A
Aesthetic Resources			S		X	X		A
Historical, Archaeological Resources			I		X	X		A
Community Economy		X(d)						
Community Population and Services			I	X		X		A
Labor Availability			I	X		X		A
Power Availability		X(e)						
Transportation Availability			I		X	X		A
H-COAL, 25,000 TPD PLANT, EASTERN U.S.								
Climatology and Meteorology			I	X		X		
Air Quality			M-S		X	X		A
Surface Water Availability	X							
Surface Water Quality			I	X		X		A
Groundwater Availability	X							
Groundwater Quality			I		X		X	A
Soils and Geology			I		X	X		
Land Availability			I(c)		X	X		A
Regional Ecology and Critical Habitats			I(c)		X	X		A
Aesthetic Resources			M-S		X	X		A
Historical, Archaeological Resources			I		X	X		A
Community Economy		X						
Community Population and Services			I	X		X		
Labor Availability			I	X		X		A
Power Availability		X(e)						
Transportation Availability			I		X	X		A

(a) Key for symbols used in adverse impact ratings:
S = Potentially significant
M = Moderate
I = Potentially insignificant

(b) Key for symbols used in mitigating measures ratings:
A = Mitigating measures described in text assumed to be implemented

(c) Assumes no other large scale development in the area coincident with power plant development or synthetic fuel.

(d) Assumes cooperation between plant and government agencies to promote reasonable, economically sound growth.

(e) Assumes power production or fuel production is a benefit to the community outweighing minor power consumption during construction or during operation.

Surface Water--The wood-to-oil plant will require about 27 gallons of water for each million Btu of product oil, while the H-Coal plant will require about 31 gallons per million Btu. The wood-to-oil conversion demand is about 210 gpm, which would not restrict availability in the river supply (this flow ranges from 780,000 to two million gpm). The H-Coal plant demand of about 9100 gpm also should not restrict available supplies (this flow ranges from 75,000 to three million gpm), although at low flow some problems could arise if other demands exist on the supply.

Aqueous discharges from the wood-to-oil plant will contain BOD (organics), TSS, TDS, and oil and grease. It is possible that residual organic substances which might be toxic or carcinogenic could be released from syngas or wood conversion processes and pass through treatment unaffected. Additional treatment (such as activated carbon adsorption for dissolved organics) might be needed. If this water were reused as cooling water as proposed, some of these materials could be released with cooling tower drift, as dicussed above.

The H-Coal plant aqueous process effluents contain TDS, TSS, and BOD. Reuse of wastewater minimizes plant makeup and reduces the impacts on surface water quality. Blowdown from the cooling tower could contain trace organics (potentially toxic), corrosion products, and chemicals used to control scaling and corrosion. High TDS blowdowns from other sources, such as the H_2 plant ash system, could also contain significant quantities of pollutants. Additional treatment may be needed before the process effluent can be safely discharged.

After adequate treatment and recycling, the process effluent streams from both plants are small (150 and 430 gpm) and should not significantly affect water quality. Storm runoff flows will be large (116 and 475 gpm) on an annual average basis. Containment and treatment of runoff will help to limit degradation of surface waters for both plants.

Groundwater--Neither facility consumes groundwater, and therefore neither facility will affect groundwater availability. Disposal of solid wastes (char, soot, slag) in wet cake form, however, could present a contamination problem to groundwater supplies. Since these wastes could contain potentially hazardous materials (nonvolatile heavy metals or hazardous organic compounds), the landfill sites used for each plant must be managed to prevent contamination of groundwater and surface water supplies.

Soils and Geology--About 110 acres of land for the wood-to-oil plant and 440 acres for the H-Coal plant will be altered by construction activities. The H-Coal plant uses proportionally less acreage, and neither facility is expected to have significant impacts on topography or soils.

Solid wastes will be disposed of by onsite burial for the wood-to-oil plant. Offsite disposal of H-Coal solid wastes from the process and from water/wastewater treatment in shallow valleys, however, will cause topographical changes. In addition, the types of wastes for both plants could significantly affect surface texture and soil quality. Particular care in reclamation of these sites will be necessary in order to insure productivity of the area.

Land Availability--Commitment of 110 acres to the wood-to-oil plant does not constitute a significant constraint on land availability. The 880 acres (including 440 acres of buffer zone) for the H-Coal plant could be a problem in a heavily developed area, but buffer zone uses such as agriculture, forestry, grazing, or other industry could be encouraged, reducing the constraints on land use.

Ecology--About 110 acres of wildlife habitat will be disturbed by construction of the wood-to-oil plant, while the H-Coal plant would disturb up to 440 acres. These impacts will be insignificant regionally if care is used in siting the plant to avoid critical habitat, riparian woodlands (in the case of H-Coal), or other important or unique vegetation. In the H-Coal case, ecological impacts and their significance in the region would depend also on the degree of existing and planned development and, therefore, the rarity of natural habitats.

Impacts on vegetation, wildlife, and aquatic life from degradation of air and water quality and deposition of cooling-tower drift will be similar for both facilities, with a greater area being affected by the large H-Coal facility.

Aesthetics--In the relatively undeveloped New England site area, the plant, feedstock woodpile, flare stack, and cooling-tower plume will present strong contrasts in shape, color, and texture to the wooded surroundings. In addition, the potential odors from processing and the general industrial character imparted by the coming and going of supply vehicles, human activity, equipment noise, and air emissions will be in sharp contrast to present uses. Visual accessibility may be limited by use of the surrounding woods as a screen and by implementing landscaping. However, the facility will have a significant local adverse impact on aesthetics.

The H-Coal plant will also affect aesthetics locally, but the significance may be moderated by the present uses of land in the region for industry. Care should be used in siting to avoid breaking up open space vistas. The use of landscaping, the layout of the plant to reduce visibility, and the revegetation of solid waste disposal sites offsite will also serve to modify the adverse impact.

Historic or Archaeological Resources--Care in siting either plant will minimize the potential for impact on historic or archaeological sites. If any subsurface relics are discovered during construction, salvage and protection may be necessary. Solid waste disposal sites for H-Coal will also have to be surveyed in order to ensure that no resources are buried with the wastes.

Social and Economic Effects--Approximately 145 permanent jobs will be created by wood-to-oil plant operation, while H-Coal will create 726 full-time jobs. Each facility will also generate temporary construction jobs (from several hundred for wood-to-oil to 300 to 400 for H-Coal). This employment, the wages and spending resulting from it, the capital spending by the plants, and the expanded tax bases will benefit local economies. Benefits will probably be proportionally greater in rural New England, but demands for trained labor, housing, and services will partially offset these benefits there. Little effect on labor pools, housing, or services is expected from construction and operation of the H-Coal facility.

Consumption of Resources--Table 120 shows the natural resources consumed by each facility. A wood-to-oil facility would consume relatively more land, auxiliary fuels, chemicals, and manpower as well as feedstock because of the low efficiency of conversion. The H-Coal plant would consume slightly more water per Btu of product output.

TABLE 120. RESOURCES COMMITTED TO SYNTHETIC FUEL OIL PLANTS*

Resource	Wood to Oil 1,965 tpd	Coal to Oil 27,836 tpd
Land	0.24 acre/MM Btu/hr	0.024 acre/MM Btu/hr**
Feedstock	353.7 lb/MM Btu	133.3 lb/MM Btu
Auxiliary Fuels	3,590 Btu/MM Btu	79 Btu/MM Btu
Chemicals	1.15 lb/MM Btu	0.545 lb/MM Btu
Auxiliary Power	39.5 kW/MM Btu/hr	+
Water	27.2 gal/MM Btu	31.35 gal/MM Btu
Manpower	0.078 mh/MM Btu	0.011 mh/MM Btu

*From Tables 85 and 100.
**Increases to 0.098 if a 440 acre buffer zone is included.

Summary of Scenario 3--
If the qualitative assessments summarized in Tables 118 and 119 are assigned numerical values shown in Table 110, it can be seen that coal procurement for H-Coal has a potential for posing significantly greater environmental problems than wood procurement for wood-to-oil. There is no clear difference between the environmental effects of the H-Coal or wood-to-oil processes (Table 121). The important aspects of coal procurement for H-Coal are coal refuse disposal sites and methods of disposal. Disposal of H-Coal process wastes, similarly, could be important. Isolation of potentially hazardous compounds from the air, water, soils, and biota is an important area for future study.

TABLE 121. SUMMARY OF WOOD AND COAL TO OIL IMPACTS

Site Specific Factors	Feedstock Procurement		Conversion Plants	
	Wood Residue	Coal	Wood	Coal
Climatology and Meteorology	0	0	-1	-1
Air Quality	-1	-1	-6	-9
Surface Water Availability	0	0	0	0
Surface Water Quality	-1	-7	-1	-1
Groundwater Availability	0	-7	0	0
Groundwater Quality	0	-6	-6	-6
Soils, Geology	-7	-8	-6	-6
Land Availability	-1	-6	-6	-6
Ecology	1	-9	-6	-6
Aesthetic Resources	1	-3	-10	-9
Historical, Archaeological Resources	0	0	-6	-6
Community Economy	5	5	5	5
Community Population and Services	0	0	-1	-1
Labor Availability	1	0	-1	-1
Power Availability	0	0	5	10
Transportation Availability	-6	-6	-6	-6
TOTAL	-8	-48	-46	-43

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Appendix A

PLANT EQUIPMENT LISTS

The equipment lists for four of the plant types are presented here in the following subappendices.

A-1	Wood-to-Power Plant
A-2	Straw and Manure-to-Gas Plant
A-3	Wood-to-Oil Plant
A-4	Coal-to-Power Plant

TABLE A-1. MAJOR EQUIPMENT SUMMARY — WOOD-TO-POWER PLANT

SERVICE	DESCRIPTION
	WOOD RECEIVING AND STORAGE
Chip dump hopper	1 - 14,000 cu ft under track hopper, 20 ft wide by 60 ft long by 14 ft deep
Hopper conveyor	1 - 420 tph chain conveyor, 120 in. wide by 70 ft long, 15 hp
Transfer conveyor (inclined)	1 - 420 tph belt conveyor, 48 in. wide by 300 ft long, 60 hp
Chip bins	2 - 10,000 cu ft bins, 20 ft dia by 35 ft high (with dust collectors*)
Chip blowers	2 - 7,000 cfm rotary blowers, 6 psi static pressure, 350 hp
Hydraulic dump platform	1 - 50 ton capacity tilt platform, 20 hp compressor and hydraulic system
Auger conveyors	4 - 60 tph twin-screw conveyors, 12 in. dia flight by 12 ft long, 5 hp
Chip reclaim conveyors	2 - 100 tph belt conveyors, 30 in. wide by 250 ft long, 5 hp
Transfer conveyor (inclined)	1 - 100 tph belt conveyor, 30 in. wide by 500 ft long, 20 hp
	BOILER (AIRSIDE)
Boiler feed silo	1 - 5000 cu ft bin with 0-100 tph vibrating feeder (vent dust collector)
Fuel distribution system	1 - 100 tph system - includes distribution conveyor, 4 supply lines, 4 air lock feeders and 4 rotary blowers, 30 hp
Power boiler system	1 - 484,000 lb/hr, 1250 psia, 900°F (TST) boiler - includes water wall furnace with traveling grate, tangential fuel firing system, combustion controls, two

(continued)

TABLE A-1 (Continued)

SERVICE	DESCRIPTION
	BOILER (AIRSIDE)
Power boiler system	drum baffleless tube bank boiler, superheater and desuperheater, economizer, mechanical dust collector, Ljungstrom air heater, ash reinjection system, ash hopper, soot blowers, ductwork, and complete structural steel
Forced-draft fan	1 - 155,000 cfm at 80°F F.D. fan, S.P. = 11 in. wg, 900 hp
Induced-draft fan	1 - 291,000 cfm at 312°F I.D. fan, S.P. = 12 in. wg, 1800 hp
Electrostatic precipitator*	1 - unit, 52 ft wide by 73.5 ft high by 60 ft deep, 60 ducts at 9 in. plate spacing, 98,820 sq ft plate area, 99.5% removal efficiency. 302,000 cfm at 300°F, 160 kVA
Exhaust stack	1 - 10 ft I.D. (at tip) by 175 ft high stack
	STEAM CYCLE (WATERSIDE)
Steam turbine	1 - 50,000 kW condensing turbine, nonreheat singlecase, single flow, 3600 rpm, 3ϕ, 60 Hz
Generator	1 - 60,000 kW hydrogen cooled generator with exciter and auxiliaries, 13.8 kV, 3ϕ, 60 Hz, 0.85 pf
Main transformer	1 - 55 MVA, FOA, 65°C, 13.8/115 kV, 3ϕ, 60 Hz
Unit auxiliary transformer	1 - 4000/5400/6600 kVA, 65°C, OA/FA/FOA, 3ϕ, 60 Hz, 13.8/4.16 kV
Startup transformer	1 - 3600/4800/6000 kVA, 65°C, OA/FA/FOA, 3ϕ, 60 Hz, 115/4.16 kV

(continued)

TABLE A-1 (Continued)

SERVICE	DESCRIPTION
	STEAM CYCLE (WATERSIDE)
Miscellaneous transformers	3 - 350 kVA, OA, 65°C, 4.16 kV/489/277 V, 3φ, 60 Hz
Emergency diesel generator	1 - 250 kW, 3φ, 60 Hz, 480 V, 0.8 pf
Surface condenser	1 - 2-pass single shell condenser, 50,000 sq ft H.T. area, 340,000 lb/hr at 2 in. Hga
L.P. feedwater heater	1 - 4-pass horizontal exchanger, 1750 sq ft H.T. area, 14.5 psia steam, 353,000 lb/hr waterside flow
Deaerating heater and tank	1 - 435,000 lb/hr at 307°F tray type daerator 165 psia shell, 44,000 lb/hr steam at 75 psia, 5000 gal tank
H.P. feedwater heater	1 - 4-pass horizontal exchanger, 2250 sq ft, H.T. area, 311 psia steam, 435,000 lb/hr waterside flow
Hot well pumps	2 - 780 gpm at 340 ft TDH pumps, 125 hp
Booster pump	1 - 1150 gpm at 1900 ft TDH pump, 800 hp
Boiler feed pumps	2 - 1250 gpm at 1900 ft TDH pumps, 800 hp
L.P. drain pump	1 - 89 gpm at 260 ft TDH pump, 10 hp
H.P. drain pumps	1 - 116 gpm at 3290 ft TDH pump, 175 hp
	AUXILIARY
C.W. circulating pumps	3 - 23,270 gpm at 95 ft TDH pumps, 900 hp
S.W. supply pumps	2 - 2420 gpm at 55 ft TDH pumps, 75 hp
Cooling tower	1 - 4-cell induced draft tower, 333 MM Btu/hr heat load, 18.5°F approach (61.5°F wet bulb), 15° range, 73 ft wide by 128 ft long by 60 ft overall height, 4 - 24 ft dia fans, 100 hp

(continued)

TABLE A-1 (Continued)

SERVICE	DESCRIPTION
	AUXILIARY
C.W. chlorinator	1 - 2000 lb/day automatic chlorinator with analyzer-controller
River water intake pumps	2 - 385 gpm at 120 ft TDH pumps, 20 hp
Pond water supply pumps	2 - 385 gpm at 45 ft TDH pumps, 10 hp
Fire water booster pumps	2 - 350 gpm at 230 ft TDH pumps, 40 hp
Gravity sand filter	1 - 5 ft dia filter, 3 gpm/sq ft loading, 30 in. bed depth
Filtered water storage tank	1 - 8000 gal tank, 12 ft dia by 10 ft high
Feed pumps	2 - 60 gpm at 95 ft TDH, 3 hp
Automatic chlorinator	1 - 10 lb/day chlorine injector and controller unit (150 lb Cl_2 cylinders)
Demineralizer system	1 - package system - includes 2-2 ft dia by 8.5 ft high cation vessels (50 in. bed), 1-2 ft dia by 6 ft high vacuum deaerator with vacuum pump, 2-2 ft dia by 8.5 ft high anion vessels (50 in. bed)
Demineralizer water storage tank	1 - 8000 gal tank, 12 ft dia by 10 ft high
Acid (H_2 SO_4) storage tank	1 - 350 gal tank with 10 gph metering pump
Caustic storage tank	1 - 350 gal tank with 25 gph metering pump
Regenerant feed pumps	2 - 20 gpm at 60 ft TDH pumps, 1 hp
Demineralizer water feed pumps	2 - 37 gpm at 70 ft TDH pumps, 2 hp
Sanitary waste treatment*	1 - 7200 gal per day package unit - includes biological reactor, clarifier, filter and chlorinator

(continued)

TABLE A-1 (Continued)

SERVICE	DESCRIPTION
	AUXILIARY
River water storage pond	1 - 3,000,000 gal basin, 120 ft wide by 240 ft long by 20 ft deep (17 ft SWD), clay-lined
Neutralization pit*	1 - 12,000 gal concrete basin, 15 ft wide by 15 ft long by 8 ft deep
Blowdown settling pond*	1 - 100,000 gal gunnited basin, 36 ft wide by 36 ft long by 12 ft deep
Stormwater holding pond*	1 - 3,000,000 gal clay-lined basin, 180 ft wide by 220 ft long by 12 ft deep
Phosphate storage tank	1 - 350 gal atmospheric tank with 3 gpm metering pump
Hydrazinc solution tank	1 - 350 gal atmospheric tank with 1 gpm metering pump
Morpholine solution tank	1 - 350 gal atmospheric tank with 1 gph metering pump
Dispersant solution tank	1 - 350 gal atmospheric tank with 2 gph metering pump

*Pollution control equipment.

Horsepower listed is motor drive rating.

TABLE A-2. MAJOR EQUIPMENT SUMMARY — STRAW AND MANURE-TO-GAS PLANT

SERVICE	DESCRIPTION
FEEDSTOCK RECEIVING AND PREPARATION	
Straw dump pit	1 - 6000 cu ft concrete pit, 50 ft long by 12 ft wide by 10 ft deep
Baled straw conveyor	1 - 100 tph pan conveyor, 54 in. wide by 60 ft long, 20 hp
Bale diverter	1 - transfer chute diverter, 8 ft wide by 8 ft long by 20 ft high
Straw conveyor system	1 - 200 tph reversible belt conveyor system, 42 in. wide by 4000 ft long (4 sections) 200 hp (total)
Portable belt conveyors	2 - 200 tph portable conveyors, 42 in. wide by 100 ft long, 10 hp
Baled straw conveyor	2 - 100 tph pan conveyors, 54 in. wide by 30 ft long, 10 hp
Straw unbalers	2 - automatic bale breakers, 2 hp
Primary crushers	2 - 40 tph hammermill crushers, 3/4 in. screen, 600 rpm, 350 hp
Pneumatic conveyor (straw)	1 - 80 tph pneumatic conveyor, 10 in. dia by 450 ft long, 100 hp blower[*]
Pneumatic conveyors (straw)	2 - 80 tph conveyor sections, 10 in. dia by 50 ft long, 50 hp blower[*]
Straw storage bins	8 - 50,000 cu ft bins, 40 ft dia by 40 ft high
Pneumatic conveyor (straw)	1 - 80 tph conveyor, 8 in. dia by 350 ft long, 100 hp blower[*]
Secondary crushers	2 - 22 tph hammermill crushers, 1/8 in. discharge screen, 200 hp
Pneumatic conveyors (straw)	2 - 30 tph conveyors, 2 in. dia by 75 ft long, 50 hp blowers[*]

(continued)

TABLE A-2 (Continued)

SERVICE	DESCRIPTION
FEEDSTOCK RECEIVING AND PREPARATION	
Straw pulping tank	1 - hydropulper, 20 ft dia, 20 hp (2% solids slurry)
Pulp sump	1 - 8500 gal concrete sump, 12 ft wide by 12 ft long by 8 ft deep
Cyclone feed pumps	2 - 8400 gpm at 115 ft TDH pumps, 500 hp
Primary cyclones	24 - 6 in. dia hydrocyclones (2.65 S.G.)
Secondary cyclones	12 - 16 in. dia hydrocyclones (1.1 S.G.)
Manure receiving bin	1 - 12,000 cu ft bin (live center) with 12 screw conveyors, 50 hp
Manure tube conveyors	2 - 50 tph tube flow conveyors, 8 in. dia by 1350 ft long (chain pull with discs), 15 hp
Manure pulping tank	1 - hydropulper, 12 ft dia, 5 hp (2% solids slurry)
Pulp sump	1 - 1500 gal concrete sump, 6 ft wide by 6 ft long by 6 ft deep
Cyclone feed pumps	2 - 1500 gpm at 115 ft TDH pumps, 100 hp
Primary cyclones	8 - 6 in. dia hydrocyclones (2.65 S.G.)
Secondary cyclones	4 - 16 in. dia hydroclones (1.1 S.G.)
Manure reclaim bin	1 - 6000 cu ft bin (live center) with 6 screw conveyors, 33 hp
Hydraulic dump platforms	5 - 50-ton capacity tilt platforms, 20 hp
ANAEROBIC DIGESTION	
Lime storage silo	1 - 7000 cu ft silo, 15 ft dia by 40 ft high (with collector and fan)
Lime weigh feeder	1 - 0-5 tph weigh belt feeder

(continued)

TABLE A-2 (Continued)

SERVICE	DESCRIPTION
	WASTEWATER TREATMENT
Lime slaker unit	1 - 1600 lb/hr slaker package unit - includes slaker and agitator, grit screw, transfer tank and agitator, controls
Lime slurry storage tank	1 - 17,200 gal tank, 14 ft dia by 15 ft high, 10 hp agitator
Lime slurry surge tank	1 - 17,200 gal tank, 14 ft dia by 15 ft high, 10 hp agitator
Lime slurry transfer pumps	2 - 35 gpm at 30 ft TDH pumps, 1 hp
Lime slurry storage pumps	2 - 35 gpm at 40 ft TDH pumps, 1 hp
Lime slurry surge pumps	2 - 70 gpm at 40 ft TDH pumps, 2 hp
Polymer feed system	1 - 250 lb/day package system - includes 1 - 16 cu ft polymer storage bin, feeder and disperser, 1 - 4280 gal mixing aging tank, with 5 hp agitator, 1 - 470 gal feed tank with 1 hp agitator, 2 - 1 to 5 gpm metering pumps, 1 hp
Straw feed storage tank	1 - 480,000 gal tank, 55 ft dia by 27 ft high, 150 hp agitator
Manure feed storage tank	1 - 81,000 gal tank, 24 ft dia by 24 ft high, 25 hp agitator
Straw slurry feed pumps	2 - 2000 gpm at 50 ft TDH pumps, 50 hp
Manure slurry feed pumps	2 - 350 gpm at 50 ft TDH pumps, 10 hp
Anaerobic digesters	6 - 5,640,000 gal fixed roof tanks, 200 ft dia by 24 ft deep (21 ft SWD)
Mixer-heater units	588 - 12 in. dia gas mixing guns, hot water jacketed
Recycle gas compressors	7 - 3500 scfm single-stage compressors, 14.5/27 psia, 250 hp

(continued)

TABLE A-2 (Continued)

SERVICE	DESCRIPTION
	ANAEROBIC DIGESTION
Digester effluent pumps*	8 - 375 gpm at 50 ft TDH pumps, 25 hp
Sludge centrifuges*	5 - 36 in. dia solid bowl horizontal solid bowl centrifuges, 250 hp
Sludge cake conveyor*	1 - 100 tph belt conveyor, 20 in. wide by 200 ft long, 5 hp
Sludge bucket elevator*	1 - 100 tph bucket elevator 75 ft long, 20 hp
Sludge cake conveyor*	1 - 100 tph belt conveyor with plow dischargers, 24 in. wide by 260 ft long, 10 hp
Sludge cake hopper*	1 - 432,000 cu ft hopper, 6 bin compartments, 256 ft long by 42 ft wide by 50 ft high, slide gate bottoms and bin vibrators
Primary clarifier*	1 - 74,000 gal gravity clarifier, 34 ft dia by 12 ft SWD, 5 hp drive
Sludge recycle pumps*	2 - 110 gpm at 70 ft TDH pumps, 5 hp
Aeration basin*	1 - 400,000 gal basin, 90 ft wide by 90 ft long by 10 ft SWD, 2 ft freeboard, plastic-lined
Aerators*	4 - floating mechanical turbine aerators, 25 hp
Secondary clarifiers*	2 - 52,000 gal gravity clarifiers, 28 ft dia by 12 ft SWD, 5 hp drive
Sludge recycle pumps*	4 - 200 gpm at 70 ft TDH pumps, 10 hp
Effluent polishing pond*	1 - 10,000,000 gal clay-lined basin, 260 ft wide by 495 ft long by 12 ft SWD
Polishing pond recycle pumps*	2 - 250 gpm at 70 ft TDH pumps, 10 hp

(continued)

TABLE A-2 (Continued)

SERVICE	DESCRIPTION
	GAS CLEANING
Raw gas compressor	1 - 5920 cfm (outlet) two-stage compressor, 27/325 psia, 2200 hp, with 275 sq ft precooler, 750 sq ft intercooler, 375 sq ft aftercooler
Acid gas removal system	1 - Benfield hot potassium carbonate plant (proprietary), 13.6 MM scfd (dry) feed gas - includes absorption and regeneration columns, exchangers, pumps, reboiler filter, piping, instruments and controls
Glycol dehydration system	1 - Smith Industries glycol dehydration plant (proprietary), 8.7 MM scfd (dry) feed gas - includes absorber, regenerator, exchangers, pump, heater, piping, instruments and controls
Acid gas incinerator unit[*]	1 - John Zink thermal oxidizer, waste heat boiler unit, 4.9 MM scfd (dry) acid gas feed - includes horizontal thermal oxidizer, firetube boiler, stack ducting, refractory, combustion air fan, controls
	AUXILIARIES
River water intake pumps	2 - 310 gpm at 70 ft TDH pumps, 10 hp
River water storage pond	1 - 1,200,000 gal clay-lined basin, 110 ft wide by 200 ft long by 12 ft SWD
Storage pond pumps	2 - 310 gpm at 70 ft TDH pumps, 10 hp
Potable water well pumps	2 - 20 gpm at 140 ft TDH vertical turbine pumps, 2 hp (6 in. dia casing)
Potable water storage tank	1 - 34,000 gal tank, 18 ft dia by 20 ft high (0-5 lb/day chlorinator)

(continued)

TABLE A-2 (Continued)

SERVICE	DESCRIPTION
	AUXILIARIES
Potable water supply pumps	2 - 20 gpm at 70 ft TDH pumps, 1 hp
Utility boiler	1 - 50,000 lb/hr at 75 psig package boiler - includes combustion box, burner, firetube boiler, stack, combustion air fan, ducting, and controls
Feedwater treatment unit	1 - 340 gph unit - includes cartridge filter, zeolite softener, 1000 gal feedwater storage tank, 5 gpm feedwater pump
Cooling tower	1 - 2 cell induced draft tower, 3000 gpm, 25°F range, 30°F approach (50°F wet bulb) with 2 - 96 in. dia fans, 25 hp
Circulating water pumps	2 - 3000 gpm at 45 ft TDH pumps, 75 hp
Sanitary waste treatment unit*	1 - 15,000 gal per day package unit - includes biological reactor, clarifier, filter, chlorine injector and controls

*Pollution control equipment.

Horsepower listed is motor drive rating.

TABLE A-3. MAJOR EQUIPMENT SUMMARY — WOOD-TO-OIL PLANT

SERVICE	DESCRIPTION
	WOOD RECEIVING AND STORAGE
Chip dump hopper	1 - 18,000 cu ft under-track hopper, 20 ft wide by 80 ft long by 14 ft deep
Hopper conveyor	1 - 420 tph chain conveyor, 120 in. wide by 90 ft long, 20 hp
Transfer conveyor (inclined)	1 - 420 tph belt conveyor, 48 in. wide by 280 ft long, 75 hp
Chip bins	2 - 10,000 cu ft bins, 20 ft dia by 35 ft high (with dust collectors)*
Chip blowers	2 - 7,000 cfm rotary blowers, 7 psi static pressure, 350 hp
Hydraulic dump platforms	2 - 50 ton capacity tilt platforms, 20 hp
Auger conveyors	4 - 60 tph twin-screw conveyors, 12 in. dia flights by 12 ft long, 5 hp
Chip reclaim conveyors	2 - 100 tph belt conveyors, 30 in. wide by 430 ft long, 10 hp
Transfer conveyors (inclined)	2 - 100 tph belt conveyors, 30 in. wide by 700 ft long, 20 hp
Chip distribution system	1 - transfer house - including 2-magnetic separators, belt trippers, 1 - 5 compartment bin, 16 ft wide by 50 ft long by 20 ft high, 5 - 0 to 30 tph vibrating feeders, 1 - filter dust collector and 1000 cfm fan*
Dryer bin feed conveyors	2 - 46 tph inclined belt conveyors, 20 in. wide by 260 ft long, 7½ hp
Cross conveyors	2 - 46 tph belt conveyors, 20 in. wide by 65 ft long with trippers, 2 hp
Syngas bin feed conveyors	2 - 46 tph inclined belt conveyors, 20 in. wide by 380 ft long, 10 hp

(continued)

TABLE A-3 (Continued)

SERVICE	DESCRIPTION
	WOOD RECEIVING AND STORAGE
Cross conveyors	2 - 46 tph belt conveyors, 20 in. wide by 75 ft long with trippers, 2 hp
Boiler silo feed conveyor	1 - 13 tph inclined belt conveyor, 14 in. wide by 160 ft long, 1 hp
	WOOD PREPARATION
Wood chip dryer/grinders	2 - 500 tpd package systems - includes 2 - 12 ft dia by 40 ft high feed bins with screw feed conveyors, 2 - dryer/grinder units (125 hp) with air classifiers, 1 - cyclone separator, 1 - baghouse filter collector (50,000 cfm, 99% efficient)*, 2 - 50,000 cfm fans, 12 in. wg static pressure, 125 hp, 1 - wood flour surge bin, 12 ft dia by 40 ft high
Wood flour metering units	2 - 350 tpd package systems - includes star valves, metering scale, screw conveyor and 8 ft dia by 16 ft high feed bin
Wood/oil blending tanks	2 - 10,000 gal tanks, 12 ft dia by 12 ft high, 150 hp agitator
Wood/oil slurry feed pumps	4 - 270 gpm at 8070 ft TDH diaphragm pumps, 750 hp
Wood/oil slurry recycle pumps	4 - 200 gpm at 460 ft TDH diaphragm pumps, 50 hp
	REACTION
Helical coil reactors	2 - reactor/furnace units - includes 2300 ft of 3 in., Sch 160 pipe wound into 10 ft dia by 35 ft high helical coil in 12 ft dia by 60 ft high furnace shell and hollow cone center, refractory lined, 15 MM Btu/hr H.T. duty

(continued)

TABLE A-3 (Continued)

SERVICE	DESCRIPTION
	REACTION
Hold (soak) vessels	2 - 4 ft dia by 50 ft high pressure vessels, 2600 psig at 650°F
H.P. flash tanks	2 - 6 ft dia by 18 ft (T-T) long horizontal drums (with internals), 175 psig at 600°F
L.P. flash tanks	2 - 6 ft dia by 18 ft long horizontal drums (with internals), 50 psig at 515°F
Flash gas surge drums	2 - 6 ft dia by 18 ft long vertical drums, 50 psig at 500°F
Flash gas spray towers	2 - 6 ft dia by 30 ft high towers, 8000 cfm gas loading, L/G ~3
Venturi scrubbers	2 - venturi tubes, 0.6 sq ft throat area, 10 in. wg pressure drop
Nonreversing cyclones	2 - 66 in. dia nonreversing cyclones with demister pads (25 sq ft)
Scrubbed gas surge drums	2 - 6 ft dia by 18 ft high horizontal drums, 10 psig at 100°F
Oil/water separators	2 - 2000 gal horizontal tanks, 6 ft dia by 10 ft long (with chemical addition)
Water draw pumps	2 - 100 gpm at 95 ft TDH pumps, 7½ hp
Oil draw pumps	2 - 10 gpm at 115 ft TDH pumps, 1 hp
Water surge tank	2 - 20,000 gal tanks, 16 ft dia by 13.5 ft high
Spray water supply pumps	2 - 130 gpm at 75 ft TDH pumps, 5 hp
Flash gas blowers	2 - 7000 scfm rotary blowers, 15/30 psia, 500 hp
Combustion air fans	2 - 20,000 scfm forced draft fans, 15 in. wg static pressure, 75 hp

(continued)

TABLE A-3 (Continued)

SERVICE	DESCRIPTION
	REACTION
Flash gas combustors	2 - 11.5 ft dia by 25 ft long combustion boxes with burners, controls, refractories and ducting, 70 MM Btu/hr duty
Syngas feed compressors	2 - 7300 scfm three-stage compressors with intercoolers (4 MM Btu/hr duty), 198/4000 psia at 420°F, 3000 hp
	PRODUCT SEPARATION
Raw oil pumps	4 - 50 gpm at 450 ft TDH diaphragm pumps, 15 hp
Cooling flash drums	2 - 6 ft dia by 12 ft high vertical drums with venturi inlet sections, 800 scfm vapor loading
Flash gas condensers	2 - shell and tube exchangers (250 sq ft), 2.5 MM Btu/hr duty
Overhead receivers	2 - 4 ft dia by 8 ft long horizontal drums
Flash drum pumps	4 - 50 gpm at 230 ft TDH diaphragm pumps, 7½ hp
Raw oil surge tanks	2 - 20,000 gal tanks, 15 ft dia by 16 ft high, heated and insulated
Surge tank pumps	2 - 150 gpm at 330 ft TDH diaphragm pumps, 25 hp
Oil/solvent mixing tanks	2 - 6000 gal tanks, 8 ft dia by 16 ft high, 15 hp agitators
Filter feed pumps	4 - 120 gpm at 115 ft TDH pumps, 7½ hp
Rotary vacuum filter systems	2 - package units - includes 2 - 10 ft dia by 16 ft long rotary vacuum precoat filters, 2 - 1200 gal filtrate receivers, 2 - 50 hp vacuum pumps, 1 - 1000 gal precoat mix tank with 5 hp agitator and 1 - 50 gpm precoat slurry pump

(continued)

TABLE A-3 (Continued)

SERVICE	DESCRIPTION
PRODUCT SEPARATION	
Filter vent gas condensers	2 - 150 sq ft shell and tube exchangers, 1 MM Btu/hr duty
Vent gas knock-out drums	2 - 3 ft dia by 9 ft high vertical drums
Oil/water separators	2 - 500 gal tanks, 3.5 ft dia by 8 ft long with chemical addition unit
Filter cake bins with conveyors	4 - 4 ft wide by 4 ft deep by 12 ft long bins with 2 - 2 tph screw conveyors, 9 in. dia flights by 60 ft long, 1 hp
Stream stripper-conveyors	2 - 2 tph screw conveyors (live steam injection), 9 in. dia flights by 30 ft long, 1 hp
Filter solids surge bins	2 - 25 ton capacity bins, 12 ft dia by 25 ft high with screw bottom, 1 hp
Tube-flow solids conveyors	2 - 4 in. dia by 1500 ft long tube-flow conveyors with chain pull and discs, 20 hp
Solvent surge tanks	2 - 20,000 gal tanks, 16 ft dia by 13.5 ft high
Surge tank pumps	4 - 100 gpm at 65 ft TDH pumps, 3 hp
Filtrate pumps	4 - 120 gpm at 65 ft TDH pumps, 5 hp
Stripper feed surge drums	2 - 10,000 gal drums, 12 ft dia by 12 ft high
Oil/solvent stripping columns	2 - 8 ft dia by 85 ft high (T-T) (vacuum) columns, 25 trays at 24 in. spacing
Stripper reboilers	2 - thermosiphon reboilers, 2000 sq ft H.T. area, 250 psia at 500°F steam 10 MM Btu/hr duty

(continued)

TABLE A-3 (Continued)

SERVICE	DESCRIPTION
	PRODUCT SEPARATION
Overhead condensers	2 - shell and tube exchangers, 800 sq ft H.T. area, 6.5 MM Btu/hr duty
Overhead receivers	2 - 1000 gal drums, 4 ft dia by 10 ft long
Condensate subcoolers	2 - shell and tube exchangers, 250 sq ft H.T. area, 1.5 MM Btu/hr duty
Reflux pumps	2 - 100 gpm at 40 ft TDH pumps, 2 hp
Stripper vacuum pumps	2 - 2000 scfm rotary vacuum pumps, 50 hp
Knock-out drums	2 - 2 ft dia by 6 ft high drums (pump exhaust)
Product oil transfer pumps	4 - 35 gpm at 350 ft TDH pumps, 7½ hp
Electrostatic coalescers	2 - 500 gal horizontal drums, 3 ft dia by 10 ft long with transformer and electrode plate package
Product oil/water separators	2 - 1000 gal horizontal drums, 4 ft dia by 10 ft long (with chemical addition)
Product oil draw pumps	4 - 35 gpm at 230 ft TDH pumps, 5 hp
Catalyst solution pumps	2 - 10 gpm at 170 ft TDH pumps, 1 hp
Product oil storage tanks	4 - 25,000 gal tanks, 16 ft dia by 18 ft high, heated and insulated
Product loading pumps	4 - 200 gpm at 115 ft TDH pumps, 15 hp
Solvent storage tanks	2 - 5000 gal tanks, 8.5 ft dia by 12 ft high
Solvent truck unloading pumps	2 - 200 gpm at 45 ft TDH pumps, 5 hp
Solvent transfer pumps	2 - 50 gpm at 95 ft TDH pumps, 2 hp

(continued)

TABLE A-3 (Continued)

SERVICE	DESCRIPTION
	SYNGAS PRODUCTION
Wood surge bins	2 - 4000 cu ft bins, 12 ft dia by 40 ft high (with dust collector)*
Purox^R shaft furnaces	4 - 500 tpd units, 12 ft dia by 40 ft high - includes 4 feed hoppers and 2 - high efficiency cyclone separators, 2 - 1000 cu ft cyclone solids hoppers
Slag quench tanks	4 - 4000 gal tanks, 8 ft dia by 12 ft high
Quench tank pumps	4 - 20 gpm at 70 ft TDH pumps, 1 hp
Raw syngas spray towers	2 - 6 ft dia by 30 ft high towers, 17,000 cfm gas loading, L/G ~3
Venturi scrubbers	2 - venturi tubes, 1.2 sq ft throat area, 10 in. wg pressure drop
Nonreversing cyclones	2 - 96 in. dia nonreversing cyclones with demister pads (50 sq ft)
Syngas surge drums	2 - 12 ft dia by 24 ft long (T-T) horizontal drums, 5 psig at 100°F
Scrubber water surge tanks	2 - 2000 gal tanks, 5.5 ft dia by 12 ft high with 2 hp agitator
Surge tank pumps	2 - 300 gpm at 60 ft TDH pumps, 10 hp
Raw syngas compressors	4 - 10,000 scfm three-stage compressors with intercoolers (4.7 MM Btu/hr duty), 14.7/200 psia at 298°F, 3000 hp
Benfield hot carbonate plants	2 - CO_2 removal plants (proprietary), 14.4 scfd design feed - includes absorption and regeneration columns, exchangers, pumps, reboiler, filter, piping, instruments, and controls

(continued)

TABLE A-3 (Continued)

SERVICE	DESCRIPTION
SYNGAS PRODUCTION	
Waste heat boiler units	2 - 8.5 ft dia by 22 ft long horizontal fire-tube boilers, 20,000 lb/hr steam at 75 psig (saturated), 2 - 50,000 cfm I.D. fans, 12 in. wg static pressure, 150 hp, 2 - 3.5 ft dia by 50 ft high stacks, ducting, refractories, and controls
Oxygen plant	1 - 400 tpd capacity O_2 plant (98%) - includes cold box, air compressor, oxygen compressor, auxiliaries, superstructures, piping, electrical, controls, and control house
CATALYST RECOVERY	
Rotary vacuum filter systems	2 - package filter units - includes 1 - 4 ft dia by 8 ft long rotary vacuum filter drum, 1 - 300 gal filtrate receiver, 1 - vacuum pump (7½ hp), 2 - 8 cu yd cake bins
Filtrate pumps	2 - 10 gpm at 65 ft TDH pumps, 1 hp
Catalyst solution tanks	2 - 10,000 gal tanks, 12 ft dia by 12 ft high with 10 hp agitator
Catalyst hoppers	2 - 170 cu ft bins, 6 ft dia by 10 ft high (with dust collector)*
Catalyst solution feed pumps	4 - 5 gpm at 3500 psi TDH diaphragm pumps, 20 hp
AUXILIARIES	
Utility boiler	1 - 50,000 lb/hr, 250 psia, 500°F traveling grate stoker boiler unit - includes furnace, fuel distributor, burners, grate, ash hopper, 2-drum boiler, economizer, drives, superstructure, and controls

(continued)

TABLE A-3 (Continued)

SERVICE	DESCRIPTION
	AUXILIARIES
Forced draft fan	1 - 19,000 cfm at 80°F fan, 13 in. wg static pressure, 75 hp
Induced draft fan	1 - 42,000 cfm at 500° fan, 10 in. wg static pressure, 100 hp
Electrostatic precipitator*	1 - unit 22 ft wide by 42 ft deep by 58 ft high, 13,248 sq ft plate area, 99.5% removal efficiency, 42,000 cfm at 500°F, 25 kVA
Boiler stack	1 - 4 ft I.D. by 100 ft high stack
Utility steam condenser	1 - single pass condenser, 100 sq ft H.T. area, 300 psig shell
Boiler feedwater pumps	4 - 50 gpm @ 690 ft TDH pumps, 20 hp
Condensate storage tanks	3 - 12,000 gal tanks, 12 ft dia by 14 ft high
Feedwater treatment system	1 - 20 gpm package system - includes 1 - 2 ft dia by 8 ft high vessel (cation), 1 - 2 ft dia by 6 ft high vacuum deaerator with 3 hp vacuum pump, 1 - 2 ft dia by 8 ft high vessel (anion), 1 - 8000 gal demineralized water storage tank, 2 - 20 gpm demineralized water supply pumps (1½ hp), 1 - 300 gal acid storage tank with 10 gph metering pump, 1 - 300 gal caustic storage tank with 25 gph metering pump, 2 - 20 gpm regenerant feed pumps (1 hp)
Cooling tower	1 - induced draft cooling tower, 90 MM Btu/hr heat load, 10°F approach (70°F wet bulb), 30°F range, 3-cells, 33 ft wide by 73.5 ft long (total) by 18.5 ft high with 3 - 14 ft dia fans, 75 hp
Circulating water pumps	2 - 3700 gpm at 95 ft TDH pumps, 150 hp

(continued)

TABLE A-3 (Continued)

SERVICE	DESCRIPTION
	AUXILIARIES
Automatic chlorinator	1 - 800 lb/day automatic chlorinator with residual analyzer-controller
River water intake pumps	2 - 130 gpm at 90 ft TDH pumps, 7½ hp
River water storage basin	1 - 900,000 gal clay-lined basin, 94 ft wide by 164 ft long by 10 ft SWD (plus 2 ft freeboard)
Plant water supply pumps	2 - 130 gpm at 65 ft TDH pumps, 5 hp
Gravity sand filter	1 - 6 ft dia automatic backwash filter, 85 gpm loading, 30 in. bed
Filtered water storage tank	1 - 20,000 gal tank, 15 ft dia by 16 ft high
Filtered water tank pumps	2 - 80 gpm at 130 ft TDH pumps, 5 hp
Automatic chlorinator	1 - 10 lb/day chlorine injector and controller unit (150 lb Cl_2 cylinder)
Sanitary waste treatment unit*	1 - 7200 gal per day package unit - includes biological reactor, clarifier, filter, chlorine injector, and controls
Blowdown neutralization basin*	1 - 20,000 gal concrete basin, 15 ft wide by 15 ft long by 12 ft deep
Storm water settling basin*	1 - 3,900,000 gal clay-lined basin, 154 wide by 274 ft long by 15 ft SWD (plus 2 ft freeboard)
Anaerobic digester*	1 - 800,000 gal fixed-roof tank, 75 ft dia by 2.4 ft deep (21 ft SWD), with 14 - 12 in. dia mixer-heater units
Digester gas compressors	2 - 500 scfm rotary compressors, 15/30 psia, 25 hp
Digester effluent pumps*	2 - 120 gpm at 60 ft TDH pumps, 5 hp
Solid bowl centrifuges*	2 - 30 in. dia horizontal solid bowl centrifuges, 150 hp

(continued)

TABLE A-3 (Continued)

SERVICE	DESCRIPTION
	AUXILIARIES
Centrifuge cake bins*	2 - 8 cu yd dumpster-type bins
Aeration basin*	1 - 250,000 gal clay-lined basin, 60 ft wide by 100 ft long by 8 ft SWD (plus 2 ft freeboard)
Aerators*	4 - floating mechanical turbine aerators, 20 hp
Secondary clarifier*	1 - 24,000 gal gravity clarifier (concrete), 18 ft dia by 13 ft SWD, 5 hp drive
Sludge recycle pumps*	2 - 80 gpm at 45 ft TDH pumps, 2 hp
Clarifier effluent wet well*	1 - 1600 gal concrete sump, 6 ft wide by 6 ft long by 8 ft deep
Effluent pump*	1 - 160 gpm at 45 ft TDH pump, 5 hp
Gravity sand filters*	2 - 7 ft dia automatic backwash filters, 150 gpm loading, 30 in. bed
Main transformer	1 - 17/23/29 MVA, 65°C, OA/FA/FOA, 115/13.8 kV, 3ϕ, 60 Hz
4.16 kV LCC transformers	2 - 2400 kVA, OA, 65°C, 13.8/4.16 kV, 3ϕ, 60 Hz
480 V LCC transformers	4 - 1200 kVA, OA, 65°C, 13.8 kV/489V/277V, 3ϕ, 60 Hz
Emergency diesel generator	1 - 500 kW, 3ϕ, 60 Hz, 480 V, 0.8 ρf

*Pollution control equipment.

Horsepower listed is motor drive rating.

TABLE A-4. MAJOR EQUIPMENT SUMMARY — COAL-TO-POWER PLANT

SERVICE	DESCRIPTION
	COAL HANDLING
Barge unloading system	1 - 1500 tph inclined boom unloading structure, 87 ft long, 3 rows of 6 ft wide buckets on chain conveyors, 50 ton surge bin with 1000 tph apron feeder, 100 hp
Transfer conveyor (elevated)	1 - 1000 tph belt conveyor, 42 in. wide by 3000 ft long, 3000 hp
Transfer and sample house	1 - transfer house with magnetic separators, transfer chute and 2-stage coal sample system with dust collection* (ducts, fabric filter collector, and fan)
Stacker conveyor (inclined)	1 - 1000 tph inclined belt conveyor, 42 in. wide by 1000 ft long with belt tripper and telescopic chute, 260 hp
Stacker conveyor (elevated)	1 - 1000 tph belt conveyor, 42 in. wide by 140 ft long with belt tripper and telescopic chute, 25 hp
Rail car unloading system	1 - 12,000 cu ft under-track dump hopper; 8 - 100 tph vibrating feeders; 1000 tph belt conveyor, 42 in. wide by 80 ft long, 100 hp
Transfer conveyor (inclined)	1 - 1000 tph belt conveyor, 42 in. wide by 260 ft long, 100 tph
Coal reclaim system	12 - 50 tph vibrating feeders; 2 - 355 tph belt conveyors, 30 in. wide by 240 ft long, 70 hp (reclaim tunnel)
Reclaim conveyors (inclined)	2 - 355 tph belt conveyors, 30 in. wide by 240 ft long, 50 hp
Transfer house	1 - transfer house with split discharge transfer chute, fabric filter collector and fan (dust collection)*
Bin feed conveyors (inclined)	2 - 355 tph belt conveyors, 30 in. wide by 360 ft long, 75 hp

(continued)

TABLE A-4 (Continued)

SERVICE	DESCRIPTION
COAL HANDLING	
Surge bin	1 - 100 ton capacity bin with 2 - 350 tph vibrating feeders, 4000 cfm fabric filter collector
Silo feed cascade system	2 - 355 tph belt conveyors, 30 in. wide by 50 ft long, 4 - 355 tph belt conveyors, 30 in. wide by 45 ft long with belt trippers, 60 hp; 1 - 13,000 cfm fabric filter collector and fan*
Coal silos	5 - 300 ton capacity bins, 16 ft dia by 60 ft high with 60° slope bottom
Gravity feeders	5 - 50 tph feeders, 7 ft long, 2 hp
BOILER (AIRSIDE)	
Coal pulverizers	5 - 100,000 lb/hr capacity bowl- roller-tye pulverizers, 600°F, 500 hp
Pulverized coal-fired boiler	1 - 3,980,000 lb/hr, 2650 psig, 1005°F capacity balanced draft, controlled circulation, radiant heat drum-type boiler - includes water-wall furnace, tangential fuel-firing system, combustion controls, ash hoppers, steam drums, 5-stage superheater, 2-stage reheater, economizer, 4-boiler circulation pumps (900 hp), soot blowers, 2 - regenerative air preheaters, 2 - steam air heaters, duct work and complete structural steel
Forced draft fans	2 - 366,400 cfm at 80°F F.D. fans, S.P. = 14 in. wg, 1000 hp
Primary air fans	2 - 88,800 cfm at 80°F P.A. fans, S.P. = 28 in. wg, 1000 hp

(continued)

TABLE A-4 (Continued)

SERVICE	DESCRIPTION
	BOILER (AIRSIDE)
Induced draft fans	2 - 655,000 cfm at 262°F I.D. fans, S.P. = 25 in. wg, 5000 hp
Electrostatic precipitators*	2 - precipitators, each 99 ft wide by 78 ft deep by 73.5 ft high, 2 units in each, 53 ducts/unit, 116,640 sq ft plate area/unit, 99.5% efficiency, 655,000 cfm at 250°F
Chimney	1 - 18 ft I.D. (at tip) by 300 ft high concrete chimney with guided steel liner to breeching
	FGD SYSTEM*
SO_2 absorbers	3 - 32 ft dia by 100 ft high spray towers (lined), each with horizontal presaturation section, wash tray, mist eliminator, spray headers and full-cone spray nozzles
Absorber delay tanks	3 - 228,000 gal capacity atmospheric tanks (lined), 36 ft dia by 30 ft high, with 125 hp top-mounted agitator
Absorber slurry recycle pumps	18 - 6200 gpm at 150 ft TDH pumps, 500 hp
Thickener feed tank	1 - 37,600 gal capacity atmospheric tank (lined), 20 ft dia by 16 ft high, with 40 hp top-mounted agitator
Absorber slurry bleed pumps	3 - 150 gpm at 60 ft TDH pumps, 7.5 hp
Slurry thickener	1 - 95 ft dia by 13 ft SWD gravity thickener with sludge rake mechanism, 25 hp
Wash tray recycle tanks	3 - 15,800 gal capacity atmospheric tanks (lined), 15 ft dia by 12 ft high, with 10 hp top-mounted agitator

(continued)

TABLE A-4 (Continued)

SERVICE	DESCRIPTION
	FGD SYSTEM*
Wash tray recycle pumps	3 - 2500 gpm at 150 ft TDH pumps, 200 hp
Wash tray clarifier	1 - 65 ft dia by 14 ft SWD gravity clarifier with skimmer and sludge rake mechanism, 15 hp
Clarifier overflow tank	1 - 8450 gal capacity atmospheric tank (lined), 12 ft dia by 10 ft high, with 5 hp top-mounted agitator
Overflow tank pump	1 - 1980 gpm at 170 ft TDH pump, 150 hp
Clarifier underflow pump	1 - 17 gpm at 50 ft TDH pump, 1 hp
Thickener overflow tank	1 - 4700 gal capacity atmospheric tank (lined), 10 ft dia by 8 ft high, with 5 hp top-mounted agitator
Overflow tank pump	1 - 385 gpm at 160 ft TDH pump, 30 hp
Thickener underflow tanks	2 - 338,000 gal capacity atmosphere tanks (lined), 46 ft dia by 36 ft high, with 150 hp top-mounted agitator
Thickener underflow pump	1 175 gpm at 60 ft TDH pump, 7.5 hp
Vacuum filter feed pumps	3 - 240 gpm at 65 ft TDH pumps, 10 hp
Vacuum filters (package)	3 - 12 ft dia by 22 ft long rotary vacuum belt filters, 830 sq ft filtration area - unit includes trough, filtrate receivers, vacuum pump (370 hp), piping and controls
Filtrate storage tank	1 - 338,000 gal capacity atmospheric tank (lined), 40 ft dia by 36 ft high, with 75 hp top-mounted agitator
Filtrate storage tank pump	1 - 75 gpm at 100 ft TDH pump, 5 hp

(continued)

TABLE A-4 (Continued)

SERVICE	DESCRIPTION
	FGD SYSTEM*
Vacuum filtrate overflow tanks	3 - 8460 gal capacity atmospheric tanks (lined), 12 ft dia by 10 ft high, with 7.5 hp top-mounted agitator
Filtrate overflow tank pumps	3 - 240 gpm at 30 ft TDH pumps, 5 hp
Filtrate cake conveyor	1 - 140 tph belt conveyor, 20 in. wide by 300 ft long, 15 hp
Lime storage bin	1 - 130 ton capacity bin, 15 ft dia by 30 ft high, with cyclone product separator and 30 hp fan
Lime weigh feeder	1 - 0 to 10 tph weigh feeder belt conveyor
Lime weigh feeder	1 - 0 to 10 tph weigh feeder belt conveyor
Lime transfer conveyor	1 - 10 tph belt conveyor, 10 in. wide by 100 ft long, 2 hp
Fly ash volumetric feeders	2 - 50 tph screw conveyors, 18 in. dia flights by 20 ft long, 5 hp
Fly ash transport air blowers	2 - 2800 cfm centrifugal blowers, 2.5 psig S.P., 50 hp
Pug blending mills	2 - 200 tph capacity mills, 75 hp
Stablized sludge conveyor	1 - 200 tph belt conveyor, 24 in. wide by 100 ft long, 7.5 hp
Load bin feed conveyor	1 - 200 tph belt conveyor, 24 in. wide by 100 ft long with tripper, 10 hp
Sludge loadout bins	2 - 150 ton capacity cone bottom bins, 13 ft dia by 30 ft high
Lime storage silos	2 - 1000 ton capacity silos, 30 ft dia by 70 ft high with cyclone product separator and fan (30 hp), 2500 cfm fabric filter collector

(continued)

TABLE A-4 (Continued)

SERVICE	DESCRIPTION
FGD SYSTEM*	
Lime weigh feeder (package)	1 - 0 to 10 tph weigh feeder belt, 1 hp
Lime slaker (package)	1 - 150 tpd lime slaker unit, with 10 hp agitator, 1 hp grit removal screw, piping and controls
Slurry transfer tank (package)	1 - 1690 gal capacity atmospheric tank (lined), 6 ft dia by 8 ft high, with 3 hp top-mounted agitator
Slurry transfer pump	1 - 120 gpm at 40 ft TDH pump, 3.5 hp
Slurry storage tank	1 - 74,500 gal capacity atmospheric tank (lined), 23 ft dia by 24 ft high, with 50 hp top-mounted agitator
Slurry storage tank pump	1 - 120 gpm at 50 ft TDH pump, 5 hp
Lime slurry surge tank	1 - 74,500 gal capacity atmospheric tank (lined), 23 ft dia by 24 ft high, with 50 hp top-mounted agitator
Slurry surge tank pumps	2 - 240 gpm at 100 ft TDH pumps, 15 hp
STEAM CYCLE (WATER-SIDE)	
Steam turbine	1 - 508,000 kW tandem compound, 4-flow, condensing, single reheat turbine, 2400 psig/11000°F/1000°F reheat, 7 uncontrolled extraction stages, 3600 rpm, 3φ, 60 Hz, 0.95 pf
Generator	1 - 590 MVA H_2-cooled generator with exciter and auxiliaries, 22 kV, 3600 rpm, 3φ, 60 Hz, 0.95 pf
Main transformer	1 - 561 MVA, FOA, 65°C, 22/345 kV, 3φ, 60 Hz
Unit auxiliary transformer	1 - 37/49.2/61.8 MVA, OA/FA/FOA, 65°C, 21 kV delta, 7.2/4.16 kV, 3φ, 60 Hz
Startup transformer	1 - 37/49.2/61.8 MVA, OA/FA/FOA, 65°C, 21 kV delta, 7.2/4.16 kV, 3φ, 60 Hz

(continued)

TABLE A-4 (Continued)

SERVICE	DESCRIPTION
	STEAM CYCLE (WATER-SIDE)
Auto transformer	1 - 200 MVA, FOA, 65^{o}C, 345/230-34.5 kV 3ϕ, 60 Hz
Misc. 480 V transformers	4 - 1725 kVA, 4-1333 kVA, 4-1150 kVA, 4-750 kVA, OA, 65^{o}C, 7.2 kV/480/277 V, 3ϕ, 60 Hz
Emergency diesel generator	1 - 1000 kW, 0.8 pf, 480/277 V, 3ϕ, 60 Hz
Surface condenser	1 - twin shell, 2-pass divided waterbox condenser, 234,000 sq ft H.T. area, 2480 MM Btu/hr, 2,462,000 lb/hr steam at 3.85 in. Hga, with air ejector and exhauster condensers
L.P. feedwater heater	1 - U-tube horizontal 2-pass exchanger, 5850 sq ft H.T. area, 89 MM Btu/hr, 1,311,800 lb/hr water-side flow (design), 50 psig shell
L.P. feedwater heater	1 - U-tube horizontal 2-pass exchanger, 3750 sq ft H.T. area, 44 MM Btu/hr, 1,311,800 lb/hr water-side flow, 50 psig shell
L.P. feedwater heater	1 - U-tube horizontal 2-pass exchanger, 6730 sq ft H.T. area, 84 MM Btu/hr, 2,623,600 lb/hr water-side flow, 50 psig shell
Deaerating heater and tank	1 - 3,727,000 lb/hr (outlet) at 311^{o}F tray deaerator with internal vent condenser, 8 ft dia by 26 ft high, 258,850 lb/hr steam flow at 66.5 psia, 12 ft dia by 63 ft long storage tank
I.P. feedwater heater	1 - U-tube horizontal 2-pass exchanger, 11,660 sq ft H.T. area, 249 MM Btu/hr, 3,370,200 lb/hr water-side flow, 225 psig shell
I.P. feedwater heater	1 - U-tube horizontal 2-pass exchanger, 10,480 sq ft H.T. area, 127 MM Btu/hr, 3,370,200 lb/hr water-side flow, 350 psig shell

(continued)

TABLE A-4 (Continued)

SERVICE	DESCRIPTION
	STEAM CYCLE (WATER-SIDE)
H.P. feedwater heater	1 - U-tube horizontal 2-pass exchanger, 14,590 sq ft H.T. area, 259 MM Btu/hr, 3,370,200 lb/hr water-side flow, 725 psig shell
Boiler feed pumps	2 - 4900 gpm (407°F) at 8264 ft TDH 5-stage pumps, 9615 bhp, with steam turbine drives, 174.7 psig/720°F inlet, 3.85 in. Hga exhaust
Booster pumps	2 - 4800 gpm (297°F) at 950 ft TDH pumps, 1500 hp
Condensate pumps	3 - 3600 gpm (124°F) at 600 ft TDH 5-stage pumps, 750 hp
Condensate storage tank	1 - 175,000 gal capacity atmospheric tank, 43 ft dia by 16 ft high
Condensate transfer pump	1 - 1000 gpm at 40 ft TDH pump, 15 hp
Auxiliary boiler	1 - 150,000 lb/hr, 250 psig (saturated) package steam boiler, natural gas-fired
	AUXILIARIES
Circulating water pumps	2 - 90,000 gpm at 85 ft TDH pumps, 2500 hp
Service water pumps	2 - 12,000 gpm at 60 ft TDH pumps, 250 hp
Condenser waterbox drain pump	1 - 1000 gpm (118°F) at 70 ft TDH pump, 25 hp
Cooling towers	2 - 8 cell induced draft towers, each 71 ft wide by 288 ft long by 59.5 ft high, 8 - 28 ft dia fans, 200 hp, 2700 MM Btu/hr total heat load, 30°F range, 9°F approach

(continued)

TABLE A-4 (Continued)

SERVICE	DESCRIPTION
	AUXILIARIES
Chlorination (package)	1 - 8,000 lb/day capacity unit, includes V-notch chlorinator, injector analyzer and controls, electric evaporator unit, expansion tank, and tank car air padding unit
Chlorine injector water booster pump	1 - 300 gpm at 370 ft TDH 2-stage pump, 50 hp
Sulfuric acid storage tank	1 - 10,000 gal capacity atmospheric tank, 12 ft dia by 12 ft high, with 2-acid metering pumps, 30 gph, 1/3 hp
Dispersant storage tank	1 - 4,000 gal capacity horizontal tank, 7 ft dia by 14 ft long, with 2 dispersant metering pumps, 1 gph, 1/4 hp
Corrosion inhibitor storage tank	1 - 4000 gal capacity horizontal tank, 7 ft dia by 14 ft long
Demineralizer feed pumps	2 - 150 gpm at 240 ft TDH pumps, 20 hp
Cation exchange units	2 - 120 gpm at 9.5 gpm/sq ft cation exchange vessels, 4 ft dia by 9 ft high, 52.5 in. bed depth (55 cu ft resin)
Anion exchange units	2 - 120 gpm at 9.5 gpm/sq ft anion exchange vessels, 4 ft dia by 5 ft 2 in. high, 30.5 in. bed depth (32 cu ft resin)
Mixed-bed exchange units	2 - 120 gpm at 17 gpm/sq ft mixed-bed vessels, 3 ft dia by 13 ft 7 in. high, 34 in. bed of cation resin (20 cu ft) and 47.5 in. bed of anion resin (28 cu ft)
Sulfuric acid storage tank (66° Be)	1 - 5000 gal capacity atmospheric tank, 8 ft dia by 13 ft long, with 1 acid transfer pump, 4 gpm, 1 hp

(continued)

TABLE A-4 (Continued)

SERVICE	DESCRIPTION
	AUXILIARIES
Caustic storage tank (50% NaOH)	1 - 5000 gal capacity atmospheric tank, 8 ft dia by 13 ft long, with caustic transfer pump, 6 gpm, 1.5 hp
Hydrazine solution tank (35% solution)	1 - 1000 gal capacity skid-mounted tank, 6 ft dia by 5 high, with 2 hydrazine metering pumps, 6 gph, 1/3 hp
Phosphate solution tank	1 - 5000 gal capacity skid-mounted tank, 10 ft high, with 3 hp side-mounted agitator and 2-metering pumps, 25 gph, 3 hp
Ammonia storage tank	1 - 5000 gal capacity horizontal tank, 8 ft dia by 12 ft long, 45 psig/120°F shell with vent condenser
Ammonia solution tank (10% solution)	1 - 1000 gal capacity tank, 5 ft dia by 8 ft high, 45 psig/120°F shell with vent condenser, 2 - metering pumps, 6 gph, 1/3 hp
Potable water pump	1 - 35 gpm at 250 ft TDH 2-stage pump, 7.5 hp
Potable water storage tank	1 - 11,500 gal capacity atmospheric tank, 15 ft dia by 9 ft high, with hypochlorite solution feed system
Raw water booster pump	1 - 1000 gpm at 55 ft TDH pump, 20 hp
Dual media gravity filters	2 - 500 gpm at 3 gpm/sq ft gravity filters, 15 ft dia by 16 ft high, 3 ft bed of anthrafilt over sand
Filtered water clearwell	1 - 100,000 gal capacity concrete pit, 30 ft wide by 30 ft long by 16 ft deep
Filter backwash pumps	2 - 1700 gpm at 165 ft TDH pumps, 100 hp
Spent backwash tank*	1 - 20,000 gal capacity atmospheric tank, 15 ft dia by 16 ft high, with 25 gpm sludge pump, 2.5 hp
Main firewater pumps	2 - 750 gpm at 288 ft TDH pumps, 100 hp

(continued)

TABLE A-4 (Continued)

SERVICE	DESCRIPTION
AUXILIARIES	
Jockey pump	1 - 60 gpm at 288 ft TDH pump, 10 hp
Scrubber water supply pumps	2 - 350 gpm at 165 ft TDH pumps, 25 hp
Sealwater booster pumps	2 - 50 gpm at 165 ft TDH pumps, 5 hp
Pond water pumps	3 - 2200 gpm at 55 ft TDH pumps, 50 hp
River water intake pumps	3 - 2200 gpm at 150 ft TDH wet pit pumps, 125 hp
River water storage pond	1 - 18,200,000 gal earthen basin, 305 ft wide by 520 ft long by 22 ft deep (20 ft SWD), 2:1 sloped sides (compacted)
Demineralizer waste neutralization tank*	1 - 25,000 gal capacity atmospheric tank, 19 ft dia by 12 ft high
Boiler blowdown collection tank*	1 - 5000 gal capacity tank, 10 ft dia by 9 ft high, 5 psig/185°F shell
Blowdown settling basin*	1 - 750,000 gal capacity concrete basin, 60 ft wide by 120 ft long by 15 ft deep, with 50 gpm sludge pump, 5 hp
Sanitary wastewater treatment unit*	1 - 25,000 gal per day package unit, includes biological reactor, clarifier, gravity filter, and chlorinator (hypochlorite)
Coal pile run-off pond*	1 - 1,150,000 gal earthen basin (plastic-lined), 112 ft wide by 184 ft long by 10 ft deep, 2:1 sloped sides
Stormwater holding pond*	1 - 7,800,000 gal earthen basin (clay-lined), 200 ft wide by 362 ft long by 18 feet deep (15 ft SWD), 2:1 sloped slides

(continued)

TABLE A-4 (Continued)

SERVICE	DESCRIPTION
	AUXILIARIES
Ash sluice water surge bin*	1 - 25,000 gal bin, 15 ft wide by 15 ft long by 16 ft deep (sloped bottom)
L.P. ash circulating pumps*	4 - 500 gpm at 200 ft TDH pumps, 50 hp
H.P. ash sluice pumps*	2 - 500 gpm at 200 ft TDH pumps, 50 hp
Coal mill rejects sluice pumps*	2 - 100 gpm at 250 ft TDH pumps, 20 hp
Surge tank sludge pumps*	2 - 50 gpm at 95 ft TDH pumps, 5 hp
Bottom ash ponds*	3 - 460,000 cu ft capacity earthen basins (clay-lined), 160 ft wide by 320 ft long by 14 ft deep (12 ft SWD), 2:1 sloped sides, decant section with 12 ft high weir across width
Ash pond recycle pumps*	3 - 500 gpm at 95 ft TDH wet-pit pumps, 20 hp
Blowdown basin recycle pump*	1 - 500 gpm at 90 ft TDH pump, 20 hp
Switchyard CPI separator*	1 - 500 gpm capacity 2-plate pack unit (1000 sq ft), with 5 gpm oil sump pump, 1 hp
Precipitator flyash fludizing blowers*	3 - 300 cfm centrifugal blowers, 3.5 psi diff. pressure, 15 hp
Flyash transport blowers*	3 - 1400 cfm positive displacement blowers, 11.5 psi diff. pressure, 125 hp
Flyash storage silos*	2 - 475 ton capacity silos, 24 ft dia by 60 ft high, with cyclone product separator and 6000 cfm filter collector (1500 sq ft)
Flyash silo fluidizing blowers*	2 - 900 cfm positive displacement blowers, 6 psi diff. pressure, 50 hp

*Indicates pollution control equipment
Horsepower listed is motor drive rating.

APPENDIX B

BIOMASS AND COAL FEEDSTOCK AVAILABILITIES

Biomass and coal resources are not uniformly distributed throughout the United States. In fact, high concentrations of both biomass residues and coal in the same local area are not very common. The low bulk densities and the relatively low concentrations of most types of biomass residues tend to militate against biomass conversion facilities on the same large scale as the proposed commercial coal conversion facilities. This appendix briefly discusses both biomass and coal resource availabilities in relation to the hypothetical biomass and coal conversion plants described in the regional scenarios.

FOREST RESIDUE IN THE SOUTH CENTRAL REGIONAL SCENARIO

Availability of sufficient forestry residue within a reasonable haul distance to a biomass conversion plant would be an important consideration in plant siting. The influence of wood cost on the cost of electricity was shown in Section 3. In the south central region indicated in the scenario, SRI reported forestry waste (logging, mill bark, and mill wood) for three of the states as (32):

Alabama	5,381,990 dry tons per year
Georgia	5,623,474 dry tons per year
Mississippi	4,380,302 dry tons per year

The 50 MWe hypothetical plan would consume about 250,000 dry tons per year of forest residue, so that each state could potentially support a number of wood-to-power plants. Seasonal availability is estimated as 20 percent — first quarter, 30 percent — second quarter, 30 percent — third quarter, and 20 percent — fourth quarter (18).

As an example of residue resources available on a more local level, SRI also indicates that there are potentially about 1.7 million dry tons of logging waste and collected forestry waste within 36 mean transport miles of Demopolis, Alabama (18). County totals near Demopolis are listed as:

Alabama County	Wasted Forestry Residue (dry tons/year)
Choctaw	218,800
Clark	307,000
Greene	62,400
Marengo	135,000

Alabama County	Wasted Forestry Residue (dry tons/year)
Monroe	152,000
Sumpter	151,600
Washington	145,300
Wilcox	163,700
Total	1,335,800

It is likely that enough residue could be collected in this area at a reasonable cost for one or more 50 MWe size units. Other localities such as southeastern Mississippi may also be capable of supporting a wood-fired power plant or a co-fired wood/coal plant.

The residue is anticipated to be primarily tops, branches, stumps, and mill bark of such species as longleaf, shortleaf, slash, and loblolly pines. Compositions and heating values of various species (woods and bark) are reported elsewhere (3, 40, 44). Heating values for southern pine wood and bark are on the order of 8600 to 9400 Btu/lb (oven dried). Collection costs vary with the specific situation. Twenty dollars a dry ton was used as a base delivered price for chipped forest residue plus mill bark. A MITRE Corp. report indicates a delivered cost of about $23 per ton in the South (40).

COAL IN THE SOUTH CENTRAL REGIONAL SCENARIO

Alabama is the only major coal producing state in this region. The deposits are divided into four fields. In 1968, estimated strippable reserves were about 164 million tons. More than 65 percent of the 1975 production (over 22 million tons) was strip mined (21). Three counties (Jefferson, Tuscaloosa, and Walker) produced about 9-1/2 million tons of strip-mined coal in 1975 (21). The rank is primarily high-volatile A and B bituminous, and sulfur content is on the order of 1 to 2 percent. Production would be more than sufficient to support a 500 MWe plant in the region over a 30-year life (about 22 million tons). In 1974, Alabama had more than 9000 megawatts of coal-fired power plant capacity, though most of the coal used was not produced in the state. A similar situation exists in Georgia where coal production is virtually nil. Delivered coal cost also varies widely. In 1974, the averages for Alabama and Georgia were about $16 and $17 per ton, respectively (45). A range of 20 to 50 dollars per ton is likely today.

STRAW AND MANURE IN THE MIDWEST REGIONAL SCENARIO

The midwest region indicated in Figure 1 is a large source of crop residue and animal residues. Most of the crop residues are returned to the land (32). Wheat straw residues for three of the states listed as returned are (32):

Kansas	15,453,557 dry tons per year
Nebraska	4,442,278 dry tons per year
Missouri	1,169,578 dry tons per year

The hypothetical biogas plant would consume about 290,000 dry tons per year of wheat straw. Potentially, Kansas and Nebraska could support a number of plants were residue judiciously collected. Seasonal availability is 100 percent — third quarter. Storage of collected straw for long periods could be a drawback.

On a local level, the crop residues (mostly wheat straw) in five Kansas counties indicate the resource potential for support of one or more biogas plants (32):

Kansas County	Returned Crop Residue (dry tons/year)
Butler	171,800
McPherson	360,000
Reno	507,100
Sedgwick	389,000
Sumner	666,000
Total	2,093,900

Other localities in the region with high wheat straw densities could potentially support a biogas plant also. The amount of material that can be removed from the fields without unacceptable soil damage may limit the number and size of biogas plants.

The wheat composition used for the conceptual design is primarily from a Battelle report (31). Collection costs will vary with the specific situation. SRI estimated costs at roadside of, say, 6 to 20 dollars per ton for crop residue (18). In a separate site survey analysis for the Weld, Colorado area, SRI estimated the delivered cost to a hypothetical conversion plant ranged from 12 to 26 dollars per dry ton (12).

Cattle manure resources in the scenario region are substantial, but much of the waste is returned to the land.

For cattle on feed, state totals given by SRC are (32):

State	Manure Returned dry tons/yr	Wasted dry tons/yr
Kansas	775,866	77,703
Nebraska	686,219	343,089
Iowa	885,577	239,309
Missouri	140,548	61,721

The hypothetical plant would consume about 50,000 dry tons per year, and the above statewide totals indicate that a number of biogas plants could potentially be supported in this region. Seasonal availability is approximately uniform throughout the year.

Plant locations would probably be limited to areas with high concentrations of cattle confined on feed: i.e., large feedlots. For a two-feedstock type of biogas plant, sufficient quantities of both wheat straw and manure should be available in the same locality. As an example, the five Kansas counties cited above have returned and wasted manure totals of (32):

Kansas County	Returned and Wasted Manure (dry tons/year)
Butler	22,470
McPherson	14,270
Reno	15,550
Sedgwick	15,070
Sumner	10,940
Total	78,300

Although 50,000 tons per year from this area could theoretically be available to a biogas plant, collection of manure from a wider area might be necessary in order to ensure an adequate supply. Other localities in Iowa and Nebraska could also be candidates for a biogas plant with manure as a feedstock. Large feedlot operations could possible be induced in a locality by the biogas plant developer.

Composition of the cattle manure used in the conceptual design was based on data reported by Battelle (3). SRI estimated collection costs at roadside for manure in the Weld, Colorado study area at $0.75 to $1.50 per wet ton (12). Transportation costs would have to be added to arrive at a delivered price per ton. Location of a biogas plant near large feedlot operations would be desirable to minimize the delivered cost of manure.

COAL IN THE MIDWEST REGIONAL SCENARIO

The hypothetical coal gasification plant would consume about 6.7 million tons per year of western coal shipped by train to the plant. Although Kansas, Missouri, and Iowa have strippable reserves sufficient to support more than one commercial gasification plant, the 1975 annual production from strip mines was less than seven million tons in total (28). Use of a low-sulfur western coal is a more likely scenario for a large gasification plant because of the much larger current production. Statewide production in both Montana and Wyoming exceeds 20 million tons annually and strippable reserves of sub-bituminous and lignite coals exceed 70 billion tons (21).

In Wyoming, for example, about two-thirds of the steam coal production is shipped to power plants in other states including Nebraska, Kansas, Iowa, and Missouri, Some of the large strip mines planned in Wyoming could produce more than 10 million tons annually. Campbell County in the Powder River Coal Basin, for example, has a potential for producing about 120 million tons per year from 12 to 15 mines in the county (46). One large strip mine there could supply all the coal requirements for the gasification plant.

The cost of western coal delivered by unit train to the midwest region in 1978 could range from $10 to $25 per ton.

FOREST RESIDUE IN THE NORTHEAST REGIONAL SCENARIO

Total logging residues in the New England region were estimated in an ERDA report as more than 30 million dry tons for the year 1970 (46). SRI estimates of forestry waste for three New England states were (32):

Maine	2,033,000 dry tons per year*
New Hampshire	310,000 dry tons per year
Vermont	218,700 dry tons per year

The wood-to-oil plant would consume about 360,000 dry tons per year. Maine could support at least potentially one or more 2000-ton-per-day wood-to-oil plants operated on forestry waste alone. Seasonal availability is estimated (18) as 20 percent — first quarter, 30 percent — second quarter, 30 percent — third quarter, and 20 percent — fourth quarter. In the study area report, SRI's availabilities were 28, 16, 28, and 28 percent, respectively (12).

As an example of localized residue resources, SRI reported that there is about 350,000 dry tons per year of logging and collected forestry waste within 32 mean transport miles of the W.F. Wyman steam electric station at Yarmouth, Maine (18). County totals in western Maine are summarized below (32):

Maine County	Wasted Forestry Residue (dry tons/year)
Somerset	241,000
Franklin	168,000
Oxford	612,000
Cumberland	56,000
Androscoggin	51,000
Sagadahoc	40,000
Lincoln	65,000
Kennebec	58,000
Waldo	59,000
Total	900,000

This area is a likely candidate for a biomass conversion plant in terms of resources available. Residual fuel oil use by industry in Maine is more than half of the total energy use (12), so that a wood-to-oil plant is a possible candidate for this area.

The average composition of wood feedstock for the conceptual plant was calculated as a mixture of 80 percent pine and 20 percent spruce bark from composition data presented by Battelle (3). Costs for delivered wood residues in Maine were estimated by SRI as $20 to $60 per dry ton for logging residue and $4 to $8 per dry ton for mill bark (12).

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*Reported as about 3.4 million tons in a DOE report (Ref. 12, pp. V11-1 to 35).

COAL IN THE NORTHEAST REGIONAL SCENARIO

In the coal-to-fuel oil region, Pennsylvania and West Virginia are the only major coal producing states. In 1975, these two states produced about 44 and 88 million tons, respectively, of deep-mined bituminous coal (21).

The conversion scenario assumed the hypothetical H-Coal plant is located fairly near underground coal mines with enough capacity to supply about 9.3 million tons per year. As an example, Green and Washington counties in southwestern Pennsylvania produced about 18 million tons of deep-mined coal in 1975, nearly all from the Pittsburgh seam (21). In-place reserves of Pittsburgh coal were about 7 billion tons in 1970, so that the reserves would be more than adequate to support one or more commercial coal liquefaction plants over a 10-year operating life.

Fluor based their conceptual H-Coal plant design on an Illinois No. 6 coal. Braun's example of an eastern coal (Pittsburgh No. 8) as indicated in Table B-1 is somewhat similar in composition to the Illinois coal. For the northeast scenario, it could be considered as the hypothetical plant feedstock with roughly similar gross outputs of products. The cost of high-sulfur coal delivered to the nearby hypothetical plant in this region would probably be in the range of $20 to $40 per ton in 1978. Cost of delivered coal to power plants in Pennsylvania averaged about $18 per ton in 1974 (45).

Table B-1. COMPARISON OF EASTERN COAL COMPOSITIONS - COAL LIQUEFACTION SCENARIO

Coal Analysis	Illinois No. 6, % wt*		Pittsburgh No. 8, % wt**	
	As received	Ultimate	As received	Ultimate
Carbon	63.48	70.50	67.21	71.50
Hydrogen	4.81	5.40	4.72	5.02
Nitrogen	0.86	0.95	1.15	1.23
Oxygen	7.28	8.10	5.14	6.52
Sulfur	4.45	4.90	4.16	4.42
Ash	9.12	10.15	10.62	11.30
Moisture	10.00	-	6.00	-
	100.00	100.00	100.00	100.00
Heating value (HHV) Btu/lb	11,900	13,222	12,400	13,190

*Fluor report (Ref. 6)

**Braun report (Ref. 7)

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APPENDIX C

COST ESTIMATION AND ECONOMIC EVALUATION METHODS

Capital, operating, and product cost estimates were performed for one coal and three biomass conversion concepts. The concepts evaluated are:

- Coal-to-Power: direct combustion of coal to generate electrical power (Section 3)
- Wood-to-Power: direct combustion of wood chips (forest residue) to generate electrical power (Section 3)
- Wheat Straw and Manure-to-Gas: anaerobic digestion of the biomass feedstock to product pipeline quality gas (Section 4)
- Wood-to-Oil: based on the Pittsburgh Energy Research Center (PERC) process, conversion of wood chips to a heavy fuel oil (Section 5)

Previously published capital and operating costs were updated and the product costs estimated for two coal conversion concepts. The concepts evaluated are:

- HYGAS^R: gasification of coal with steam and oxygen to produce pipeline-quality fuel gas (Section 4)
- H-Coal^R: catalytic hydrogenation of coal to produce synthetic fuel oil (Section 5)

The following areas of the United States were specified for each biomass and coal conversion plant site:

- Wood-to-Power: South Central (Alabama)
- Straw and Manure-to-Gas: Midwest (Kansas)
- Wood-to-Oil: Northeast (Maine)
- Coal-to-Power: South Central (Alabama)
- HYGAS: Midwest (Kansas)
- H-Coal: Northeast (Pennsylvania)

CAPITAL COSTS

The above three biomass conversion processes and one coal conversion process were estimated based on the conceptual design and engineering information prepared for the study in the form of engineering drawings, outline specifications, and equipment lists. Estimating methods consistent with the conceptual nature of the design information were employed based on informal vendor contact and extrapolation from Bechtel historical information.

The construction cost estimate is composed of field costs, engineering services, and allowance for uncertainty. The largest (dollar) category, field costs, comprises the direct cost of permanent plant equipment and the indirect cost of temporary construction materials, supervision, etc. The estimate anticipates an engineer-constructor direct-hire operation employing field construction labor forces.

The capital costs of the other two coal conversion processes were updated for comparison with the other four processes. Capital costs were originally estimated by others:

Process:	HYGAS (steam-oxygen)
Estimation Date:	First Quarter, 1976
Reference:	Factored Estimates for Western Coal Commercial Concepts, prepared by C.F. Braun and Co., for the United States Energy Reserach and Development Administration and the American Gas Association under Contract No. E(49-18)-2240 March 1, 1976 (Reference 6)
Process:	H-Coal
Estimation Date:	Second Quarter, 1975
Reference:	H-Coal Commercial Evaluation, Conceptual Design and Economic Analysis for a 25,000 Ton-per-Day H-Coal Liquefaction Plant, Case — I Fuel Oil Mode, prepared by Fluor Engineers and Constructors, Inc., for the United States Energy Research and Development Administration under Contract No. E(49-18)-2002, March 1976, final unpublished report (Reference 7)

In order to obtain consistency with the other four processes, the two coal processes were updated to first quarter, 1978, prices based on Nelson refinery and operating labor indices.

Indices used for HYGAS are:

	Nelson Refinery Index	Nelson Operating Labor Index
1st Quarter, 1978	680.0	158.0
1st Quarter, 1976	605.0	145.0

Indices used for H-Coal are:

	Nelson Refinery Index	Nelson Operating Labor Index
1st Quarter, 1978	680.0	158.0
2nd Quarter, 1975	575.5	133.0

Certain nonprocess modifications were made to the HYGAS and H-Coal base conceptual designs to reflect different site-related assumptions (see starred items in Tables 63 and 94). For HYGAS, these changes resulted in a net addition to the updated total capital cost of $13.7 million. For H-Coal, the changes resulted in a net addition to the updated total capital cost of $12.9 million.

Pricing Levels

The estimate is at first quarter, 1978, price and wage levels. No allowance has been made for future escalation.

Field Construction Costs

Elements shown in capital cost Tables 21, 35, 52, and 81 were estimated on the basis of the following discussion:

- Site and Yard--includes the cost of clearing, grubbing, and mass excavation. It also includes domestic water piping, fire water facilities, sewer and storm drainage, fences and gates
- Civil/Structural--includes buildings (administration building, shops, warehouse, auxiliary service buildings and garage) river intake structure, river water storage pond, railroad spurs, and access roads
- Process Mechanical Equipment--includes all mechanical equipment necessary to operate the plant
- Pollution Control Equipment--includes civil items such as ponds, basins, wastewater treatment, solid waste disposal and equipment required for gas cleanup, such as dust collectors, precipitators, incinerators, and FGD systems
- Piping and Instrumentation--includes all process and interconnecting piping, auxiliary piping, and necessary electrical, pneumatic and mechanical instrumentation
- Electrical--includes the main transformers, unit auxiliary transformers, start-up transformers, auto-transformers, and emergency diesel generators. Wire and cable, conduits, and plant lighting are also included

Equipment--
Budgetary suppliers' estimates based on conceptual designs and specifications were obtained verbally or in writing for approximately 80 percent of the major items. Other equipment was estimated using Bechtel data derived from recent purchase orders and vendor contacts.

Material--
Quantity evaluations were made from the drawings for the identifiable materials of concrete, steel, piping, wire and cable and these quantities were priced using current unit prices from Bechtel sources. Other materials that would be delineated on the final engineering drawings have been evaluated by experience as a percentage of the installed cost of the identified materials.

Subcontracts--
Subcontracts for equipment and materials commonly installed by subcontractors were estimated and priced in accordance with Bechtel experience from current sources.

Construction Labor--
The direct construction labor costs for the installation of the plant equipment and material were estimated using recent productivity experience and a wage rate based on labor contracts and fringe benefits for areas of the country specified for each conversion concept. These wage rates are based on a craft mix appropriate to the type of construction together with a five percent allowance for casual overtime and one percent for craft-furnished supervision. Sufficient manual labor to complete the project is assumed to be available in the project vicinity.

Indirect Field Costs--
The indirect field costs are those items of construction cost that cannot be ascribed to direct portions of the facility and thus are accounted separately. They were estimated by modifying the experience on plants of a similar nature resulting in an assessment of 70 percent of direct labor costs. The items covered by indirect field costs are as follows:

- Temporary Construction Facilities--Temporary buildings, working areas, roads, parking areas, utility system and general-purpose scaffolding

- Miscellaneous Construction Services--General job cleanup, maintenance of construction equipment and tools, material handling and surveying

- Construction Equipment and Supplies--Construction equipment, small tools, consumable supplies, and purchased utilities

- Field Office--Field labor of craft supervision, engineering, procurement, scheduling, personnel administration, warehousing, first aid, and the costs of operating the field office

- Preliminary Check-Out and Acceptance Testing--Testing of materials and equipment to insure that components and systems are operable

Engineering Services

The engineering services include engineering costs, other home office costs, and fee. Engineering includes preliminary engineering, optimization studies, specifications, detail engineering vendor-drawing review, site investigation, and support to vendors. Other home office costs comprise procurement, estimating and scheduling services, quality assurance, acceptance testing, and construction and project management. Fee is included as a function of the total project cost. The sum of these three categories falls into historically consistent percentages in the range of 10-20 percent depending on the complexity of the project. For this study, a figure of 12 percent of field construction costs has been used as typical for plants that, while new in concept, do not depart radically from basic engineering principles.

Allowance for Uncertainty

Included in the estimate is an allowance for the uncertainty that exists within the conceptual design in quantity, pricing or productivity and that is under the control of the constructor and within the scope of the project as defined. Implicitly the allowance will be expended during the design and construction of the project and it cannot be considered as a source of funds for overruns or additions to the project scope. However, experience shows that is is quite difficult to assess the degree to which future processes are understood in the hardware sense. Thus, if the conceptual arrangement of the plant components proves to be more severe than anticipated, or if additional major subsystems are ultimately found to be necessary, then the scope of the project is deemed to have been inadequately defined and this then would not be covered by the allowance. This allowance was included at 20 percent for the four Bechtel estimated plants and at 15 percent for HYGAS and H-Coal.

Other Costs

Land--

The cost of land for each plant is based on an allowance of approximately $2,000 per care (fenced plant site).

Other Owner Costs--

This item includes costs to the owner to conceive, plan, and execute the project. It generally includes the expenses for process evaluation study, planning, site surveying and selection, contractor selection, government's permit fees and other legal costs. Also included are initial chemicals and catalyst cost. For these estimates other owner costs were estimated at two percent of total construction cost.

Startup--

This item covers the expenses occurring before the full operation. It includes costs for recruiting operators, training, modification of processes to correct deficiencies, etc. Five percent of total construction cost was allowed for this expense for the biomass process and the coal-fired power plant.

Allowance for Funds During Construction--
In accordance with usual procedures, the interest on the capital cost of the plant during the construction period is allowed as a depreciable capital investment over the life of the plant. Nine percent per annum was used as the interest rate, and three-year and five-year construction periods were used for the three biomass and three coal conversion processes, respectively. It is assumed that the center of gravity of the capital spending is located at a point two-thirds from the beginning.

Working Capital--
The working capital of the plant represents the amount of money invested in the following categories:

1. Feedstock, supplies, and materials in storage
2. Final products in stock and semi-finished products in the process of being manufactured
3. Cash required on hand to pay monthly expenses, such as salaries, wages, and raw material purchase
4. Accounts payable
5. Taxes payable

A minimum of five percent of fixed capital investment was allowed for this purpose.

Design Assumptions

The following are the major assumptions for which design data were not available when the estimate was prepared.

- Site specific items which affect civil/structural costs
- Piping, instrumentation and electrical layouts

Qualifications

The following are the major qualifications in the estimate:

- Any emission offsets required are excluded
- Feedstock delivery is by others and the cost is included in the cost of feedstock
- Major utilities, such as power, are available at the plant fence line from others
- Solid sludge from the wheat straw and manure-to-gas process is disposed of at no cost. Its value as a soil conditioner is assumed to equal the cost of disposal by others. Ash residues are insignificant and are disposed of on site

- Disposal of solid wastes (ash and wastewater evaporator sludge) from HYGAS is assumed to be in the source coal mine. Disposal cost is included in the cost of delivered coal
- Costs of product distribution are excluded

Estimate Tables

The above discussion of pricing levels, field construction cost, engineering services, allowance for uncertainty, qualifications and exclusions form the basis of the estimates contained in the following tables:

- Table 21. Wood-to-Power Capital Costs (Section 3)
- Table 35. Coal-to-Power Capital Costs (Section 3)
- Table 52. Straw/Manure-to-Gas Capital Costs (Section 4)
- Table 81. Wood-to-Oil Capital Costs (Section 5)

The following two tables were updated to the same time period as the above four processes:

- Table 67. HYGAS Capital Costs (Section 4)
- Table 97. H-Coal Capital Costs (Section 5)

ANNUAL OPERATING AND MAINTENANCE COSTS

The materials, supplies, and labor for plant operation and maintenance were estimated to reflect first quarter, 1978, price and wage levels. They have been included in the estimate on the basis of the following descriptions.

Supplies

The annual costs for chemicals, diesel oil, gasoline, and other supplies consumed in the operation of the plant are included on the following basis:

- Chemicals were priced using recent supplier quotes
- Petroleum products and natural gas were priced on an average cost per gallon or MSCF

Utilities

Power was priced at $0.03 per kWh with the annual requirements calculated from the installed equipment load. Plant makeup water was priced at $0.05 per thousand gallons as an allowance for water rights.

Operating Personnel

Operating personnel costs were estimated based on manning charts and average cost per manhour for a typical operator.

Maintenance Labor and Materials

The costs of labor for plant maintenance were estimated from the manning charts and average costs per manhour for a typical maintenance person. Material was priced as being 40 percent of total maintenance, given labor as 60 percent of the total.

Supervision

The supervision costs were assumed at 15 percent of operating and maintenance labor.

Administration and Overhead

Administration and overhead costs were estimated from the manning charts with a nominal cost included for other overhead.

Local Taxes and Insurance

Property and other recurring taxes and insurance were estimated at two percent of total plant capital cost. This is a typical rate for the types of plant under consideration.

Operating Cost Tables

The above discussion of annual operating and maintenance items forms the basis of the estimates contained in the following tables:

- Table 22. Annual Operating and Maintenance Costs Wood-to-Power (Section 3)
- Table 36. Annual Operating and Maintenance Costs Coal-to-Power (Section 3)
- Table 53. Annual Operating and Maintenance Costs Wheat Straw/Manure-to-Gas (Section 4)
- Table 82. Annual Operating and Maintenance Costs Wood-to-Oil (Section 5)

The following two Annual Operating and Maintenance Cost tables were obtained from References 6 and 7. They were updated to reflect first quarter, 1978, prices and wages using the same indices that were used for capital costs.

- Table 68. Annual Operating and Maintenance Costs HYGAS (Section 4)
- Table 98. Annual Operating and Maintenance Costs H-Coal (Section 5)

PRODUCT COSTS

The product costs of energy produced by each of the three biomass and three coal conversion processes were computed by two different financial methods. They are:

- Utility financing method
- Private financing method

The procedures to calculate the production costs using these methods were obtained from the reference listed below:

> Coal Gasification Commercial Concepts Gas Cost Guidelines by Robert Skamser, C.F. Braun and Co., Alhambra, CA 91802, January, 1976. Prepared for the United States Energy Administration and the American Gas Association. Under Contract No. E(49-18)-1235 (Reference 8).

Utility Financing Method

The average product costs of energy produced from six different plants were computed on the following basis:

- 20-year project life (except two electric power plants, wood-to-power and coal-to-power — 30 years were used instead)
- Straight line depreciation on total capital cost excluding working capital
- 48 percent federal income tax rate
- 75 percent debt
- 9 percent per year interest on debt
- 15 percent return on equity

Private Financing Method

The constant product costs of energy produced from six different plants were computed on the following basis:

- 20-year project life (except two electric power plants, wood-to-power and coal-to-power — 30 years were used instead)
- 16 year sum-of-the-years'-digits depreciation on total capital investment excluding startup, allowance for funds during construction, and working capital. (For two electric power plants, 24 years were used.)

- 100 percent equity capital
- 12 percent Discounted Cash Flow (DCF) rate of return
- Total construction cost, land, owner's cost, allowance for funds during construction and working capital are treated as capital costs in Year 0
- Startup costs are treated as an expense in Year 0

Production Cost Tables and Figures

The results of calculation to compute the production cost of energy for six different processes by utilizing the two different financial analyses described above were tabulated using the feedstock cost as the parameter in the following two tables:

- Table 8. Economic Comparison Summary for Biomass and Coal Conversion Processes (based on feedstock cost, dollars per ton). (Section 2)
- Table 9. Economic Comparison Summary for Biomass and Coal Conversion Processes (based on feedstock cost, dollars per million Btu). (Section 2)

The effect of feedstock prices (dollars per ton and dollars per million Btu) on product costs are graphically displayed in Figures 40, 41, and 42. Also shown on the graphs is the effect of two different financial methods on product cost.

- Figure 40. Effect of Feedstock Cost on the Cost of Electricity (Section 6)
- Figure 41. Effect of Feedstock Cost on the Cost of Synthetic Pipeline Gas (Section 6)
- Figure 42. Effect of Feedstock Cost on the Cost of Synthetic Fuel Oil (Section 6)